CASE RESOURCES INC.

2003 *Annual Report*

CASE
RESOURCES INC.

SPECIAL AND ANNUAL GENERAL MEETING

The Special and Annual General Meeting of shareholders of the Corporation will be held on May 4, 2004 at 3:00pm in the Devonian Room at the Calgary Petroleum Club, 319-5th Avenue S.W., Calgary, Alberta.

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Photographs on cover and page 14 compliments of Kelly Nichol, Production Manager, Case Resources Inc..

Case at a Glance

Case Resources Inc. is an aggressive oil and gas exploration development and production company based in Calgary, Alberta, whose assets are in western Canada. Case's management team was appointed in September 2000. The company has grown from an average of 182 BOE/day in 2000 to 1,671 BOE/day in 2003. Case averaged 1619 BOE/day in the fourth quarter of 2003.

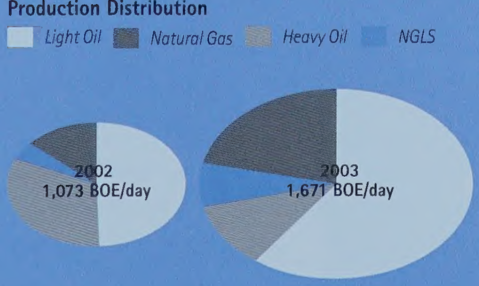
Directors, management, and their families own in excess of 35% of the outstanding shares of Case, which aligns their interests with those of other shareholders.

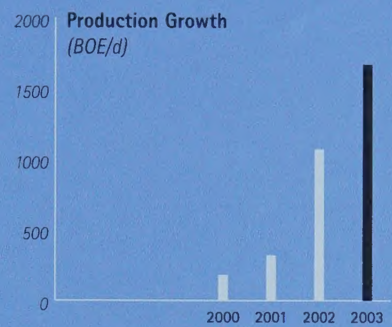
Case's strategy is to have clearly focused core production areas, with high working interests and operatorship. Case expects its properties to possess exploitation, development and exploration potential. Case prefers to own its infrastructure where possible.

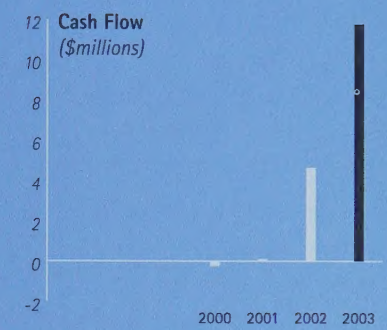
We expect to aggressively purchase assets, or other corporate entities, in order to achieve these goals. As our cash flow grows we are developing a grass roots exploration program to augment our acquisition strategies.

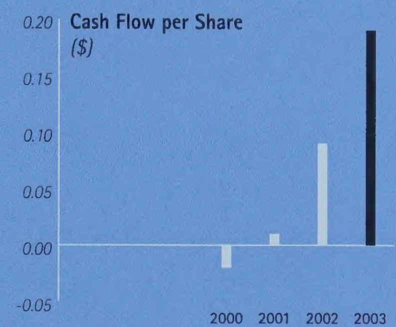
Case trades on the TSX under the symbol CAZ.

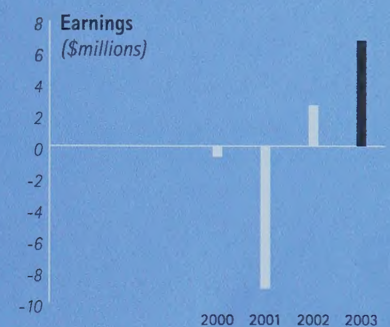
Production Distribution

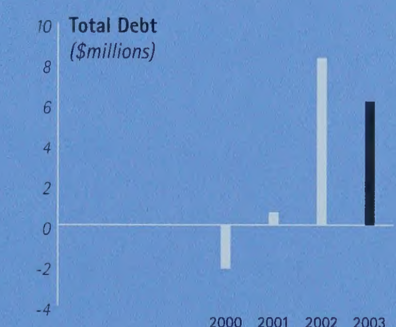


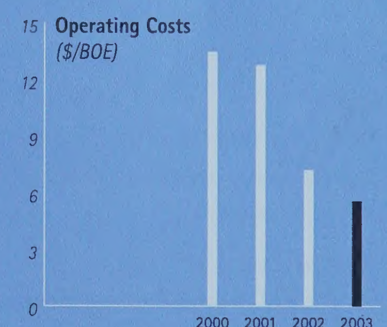


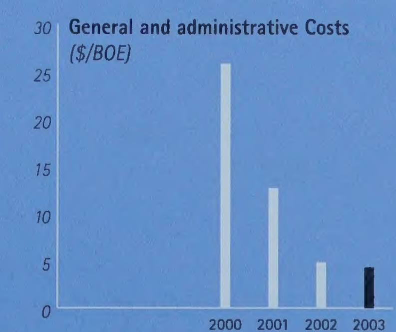


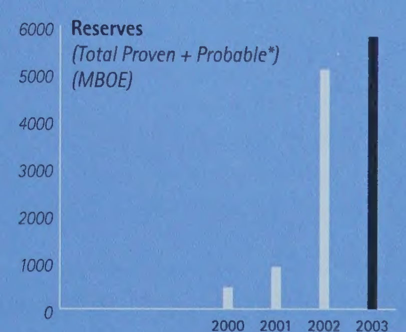












* *For 2002 and previous years the graph displays traditional "established" reserve volumes (proved + 1/2 probable reserves) for comparison with the 2003 proved plus probable reserve volumes determined in accordnace wirh National Instrument 51-101.*

OPERATING AND NETBACK HIGHLIGHTS

Years ended December 31 *(units as noted)*	2003	2002	% Change
OPERATING			
Daily Average Production *(excluding royalties)*			
Light Oil *(barrels)*	**1,006**	532	89
Heavy Oil *(barrels)*	**185**	348	(47)
Natural Gas *(thousands of cubic feet)*	**2,126**	853	149
Natural Gas Liquids *(barrels)*	**125**	51	145
Total - barrels of oil equivalent *(6:1)*	**1,671**	1,073	56
Average Sales Price *($ Canadian)*			
Light Oil *(per barrel)*	**39.98**	39.34	2
Heavy Oil *(per barrel)*	**24.22**	20.23	20
Natural Gas *(per thousand cubic feet)*	**6.64**	4.49	48
Natural Gas Liquids *(per barrel)*	**37.85**	31.82	19
Total - per of barrel of oil equivalent *(6:1)*	**38.04**	31.14	22
Proved and Probable Reserves *(before royalties)**			
Light Oil *(thousands of barrels)*	**3,523**	2,946	20
Heavy Oil *(thousands of barrels)*	**703**	759	(7)
Natural Gas *(millions of cubic feet)*	**7,411**	5,805	27
Natural Gas Liquids *(thousands of barrels)*	**316**	408	(23)
Total *(thousands of barrels of oil equivalent – 6:1)*	**5,777**	5,081	14
Undeveloped Land			
Gross *(acres)*	**22,421**	25,324	(11)
Net *(acres)*	**13,372**	8,728	53
NETBACKS AND COST *($ per barrel of oil equivalent 6:1)*			
Petroleum and Natural Gas Revenue	**38.30**	31.34	22
Royalties, net of ARTC	**(8.87)**	(6.76)	31
Operating expenses	**(5.57)**	(7.21)	(23)
Netback	**23.86**	17.37	37
General and administrative expense	**(4.30)**	(4.83)	(11)
Interest expense	**(0.23)**	(0.54)	(57)
Other income	**0.01**	0.02	(50)
Taxes	**(0.05)**	(0.14)	(64)
Cash Flow Netback	**19.29**	11.88	62
Depletion and depreciation expense	**(7.49)**	(6.61)	13
Stock option compensation expense	**(0.02)**	–	n/a
Future income tax (expense) recovery	**(0.73)**	1.37	n/a
Net Earnings	**11.05**	6.64	66

* *For comparison purposes the reserves disclosed for 2002 are proved plus 1/2 probable reserves.*

FINANCIAL HIGHLIGHTS

Years ended December 31 *(units as noted)*	2003	2002	% Change
FINANCIAL			
Petroleum and Natural Gas Revenue *($)*	**23,352,055**	12,272,209	90
Cash Flow from Operations *($)*	**11,761,467**	4,649,299	153
Per share - basic *($)*	**0.20**	0.09	122
Per share - diluted *($)*	**0.19**	0.09	111
Net Income *($)*	**6,740,299**	2,597,687	159
Per share - basic *($)*	**0.11**	0.05	120
Per share - diluted *($)*	**0.11**	0.05	120
Common Shares Outstanding			
End of Period	**60,000,179**	60,792,679	(1)
Weighted Average For Period *(basic)*	**60,295,684**	54,768,235	10
Weighted Average For Period *(fully diluted)*	**61,673,113**	54,785,696	13
Capital Expenditures, net *($)*	**8,567,022**	21,354,031	(60)
Working Capital Deficiency *($)*	**1,392,740**	811,355	72
Production Loan *($)*	**4,732,524**	7,458,345	(37)
Total Debt *($)*	**6,125,264**	8,269,700	(26)

TRANSACTIONAL ACTIVITIES

- February 2003 – disposition of essentially one half of its heavy oil producing properties for net proceeds of $2,340,697.
- April 2003 – disposition of non-core Central Alberta light oil and natural gas properties for net proceeds of $3,745,649.

CAUTIONARY STATEMENTS

As required by National Instrument 51-101 the following cautionary statements are applicable to the information contained in this Annual Report:

(1) The netback disclosed above and elsewhere in this Annual Report have been calculated by subtracting from the petroleum and natural gas revenues for each product the royalties applicable thereto (net of ARTC) and the associated operating costs.

(2) BOE's may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(3) An estimate of reserves and future net revenue for an individual property may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

CASE RESOURCES INC.

Report to Shareholders

DEAR SHAREHOLDER

I am pleased to report that by virtually all measures, Case has demonstrated significant growth in 2003. Average production was up 56% from 1,073 BOE/day to 1,671 BOE/day. Cash flow was up 153% from $4.6 million to $11.8 million. Cash Flow per share (basic) was up 122% from $0.09 to $0.20. Operating costs were down 23% from $7.21 to $5.57 per BOE. General and administrative costs were down 11% from $4.83 to $4.30 per BOE. More importantly, year end debt was down 26%, from $8.3 to $6.1 million. Further, notwithstanding the new reserve reporting requirements, our Proven and Probable reserves were also up by 14%. At the same time the number of common shares outstanding was reduced from 60.8 to 60 million, as we bought back 792,500 shares at an average price of $0.78.

The growth was funded from available cash flow and the sale of one-half of our heavy oil interests and seven small miscellaneous properties which had limited upside potential and high operating costs. Our growth came entirely from drilling, as we did not complete any acquisitions in 2003. We chose to exploit our 100% working interest property at Haynes, Alberta and remained focused on that during 2003. I should note that we have high working interests at Haynes and approximately 90% of our current production comes from this field. Accordingly, any short term production issues related to normal production turn arounds, such as workovers and/or regular maintenance or more permanent actions such as suspending wells, have significant effects on our short term production. On the one hand it is an exceptional opportunity to have a fully controlled asset but the obvious downside is that any potential short term problems in a 100% working interest project are materially magnified.

With the success of Haynes we are now in a position to actively and aggressively seek opportunities outside of Haynes which over time will allow Case to diversify its asset base. We have started to grow a new core area in the Brazeau area of Alberta where we own 16 sections of land with a 100% working interest. I am pleased to say that we are currently very active with several other initiatives and we are confident some of these efforts will ultimately result in the creation of shareholder value. Finally we expect to continue to drill at our Haynes property which still holds significant development and exploration potential.

I would like to take this opportunity to thank Mr. Rod Lebbert who was a member of our management team, who left Case at the beginning of 2004. Mr. Lebbert had been with Case since its inception, he is an excellent engineer who will be missed by all of us at Case.

Thank you to the staff and management of Case who have and continue to work extremely hard on behalf of the shareholders. The directors and I are extremely proud of their efforts.

On behalf of management and directors,

Jeff Tonken

A. Jeffery Tonken
President and Chief Executive Officer

March 26, 2004

Review of Operations

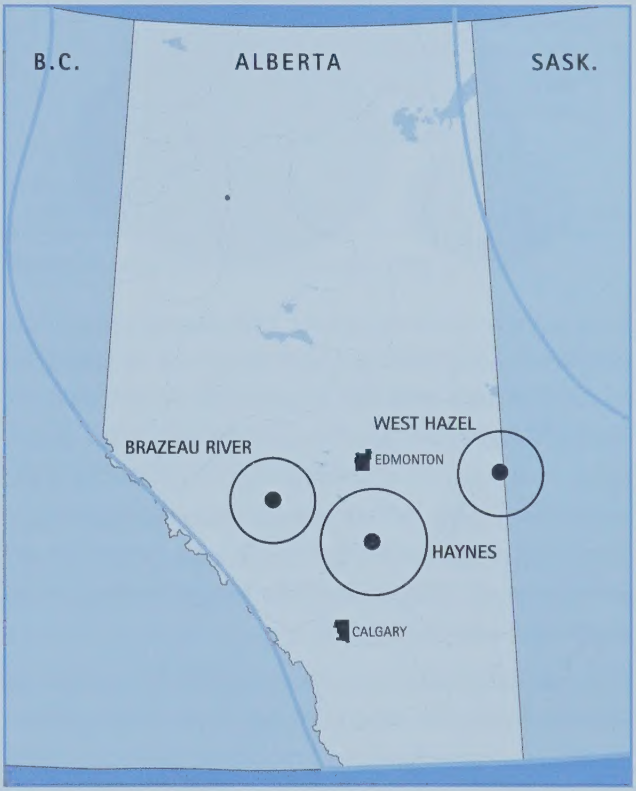
OVERVIEW

During 2003 Case implemented a rationalization of its assets and continued to focus its capital program and technical efforts on the development, exploitation and exploration of its core area of Haynes, Alberta. Case also implemented a land acquisition strategy to establish a new core area, at Brazeau in west central Alberta.

The core area of Haynes has a number of positive attributes:

- High rate, light oil wells
- Low operating costs, high netback
- Multizone exploitation potential
- High working interest ownership and control of production and processing infrastructure
- Geographic focus
- Year round access

As a result of asset rationalization, early in the year Case disposed of 212 BOE/day (approximately 50%) of its heavy oil production mainly at West Hazel Saskatchewan and approximately 150 BOE/day of light oil and natural gas production from seven small miscellaneous properties which had limited upside potential and high operating cost.



PRODUCTION

Average daily production during 2003 averaged 1,671 BOE/day comprised of 1,006 bbls of light oil, 125 bbls of natural gas liquids 185 bbls/day of heavy oil and 2,126 mcf/day of natural gas. Most of this production is from the Haynes property as shown on the following table.

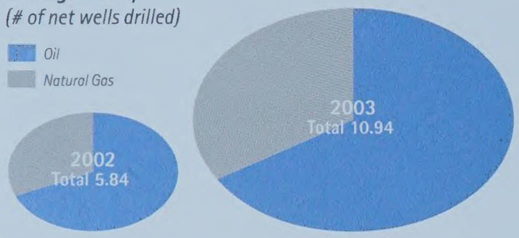
	Light Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (BOE/d)
Haynes	990	–	1,887	117	1,422
West Hazel	–	185	11	–	187
Others	16	–	228	8	62
Total	1,006	185	2,126	125	1,671

REVIEW OF OPERATIONS

DRILLING ACTIVITIES

Case participated in the drilling of 16 (10.94 net) wells during 2003 resulting in 11 (7.25 net) oil wells and 5 (3.69 net) gas wells and no dry holes. The drilling operations for 11 (9.69 net) wells were operated by Case and the drilling of 5 (1.25 net) additional wells, were operated by a third party. All wells were cased and completed and all but two net gas wells were brought on production.

Drilling Activity
(# of net wells drilled)



At Haynes, Case drilled 3 successful, 100% working interest, Nisku infill wells during March and April, which also resulted in the discovery of a new Leduc light oil pool at Haynes. In the summer months Case drilled two Belly River wells, one well is standing cased and completed and the other is producing. In the fall, Case drilled an additional 3 Nisku infill oil wells and two more Glauconite gas wells at Haynes. These activities resulted in 3 new oil producers and 2 new natural gas producers. One of the Nisku infill wells discovered another new Leduc light oil pool.

Production from the shallow gas wells has declined faster than was expected and based on these results Case is re-evaluating whether the drilling of further Belly River or Glauconite gas wells at Haynes can be justified.

At Brazeau, Case drilled one exploration well that was cased and completed for low rate natural gas. The well has not brought on production because the economics of pipelining it cannot be justified at this time.

At West Hazel Case participated in the drilling of 5 (1.25 net) infill oil wells at a 25% working interest. All five wells were successful, encountering Waseca, Sparky and/or General Petroleum pay sections and are currently producing. The drilling operations resulted in some of the existing producing wells being shut in for an extended period of time and to date not all of the previous production has been restored.

The following table sets forth a summary of the drilling activity during 2003.

2003 Drilling Activity

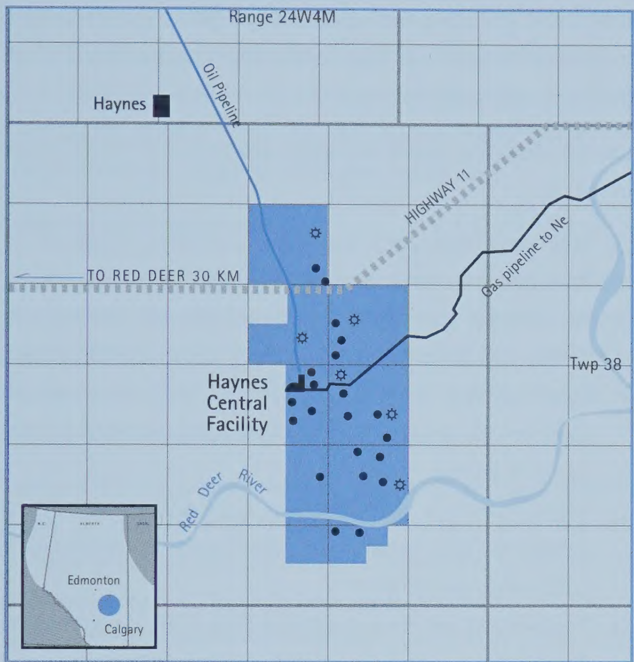
		Operated		Non-Operated		Total	
		Gross	Net	Gross	Net	Gross	Net
Oil	Exploration *	–	–	–	–	–	–
	Development	6.00	6.00	5.00	1.25	11.00	7.25
	Total	6.00	6.00	5.00	1.25	11.00	7.25
Gas	Exploration	5.00	3.69	–	–	5.00	3.69
	Development	–	–	–	–	–	0.00
	Total	5.00	3.69	–	–	5.00	3.69
D&A	Exploration	–	–	–	–	–	–
	Development	–	–	–	–	–	–
	Total	–	–	–	–	–	–
Total	Exploration	5.00	3.69	–	–	5.00	3.69
Total	Development	6.00	6.00	5.00	1.25	11.00	7.25
Grand Total		11.00	9.69	5.00	1.25	16.00	10.94

* *Two of the 100% oil development wells were drilled deeper than the Nisku development targets to explore the Leduc formation and discovered new Leduc pools.*

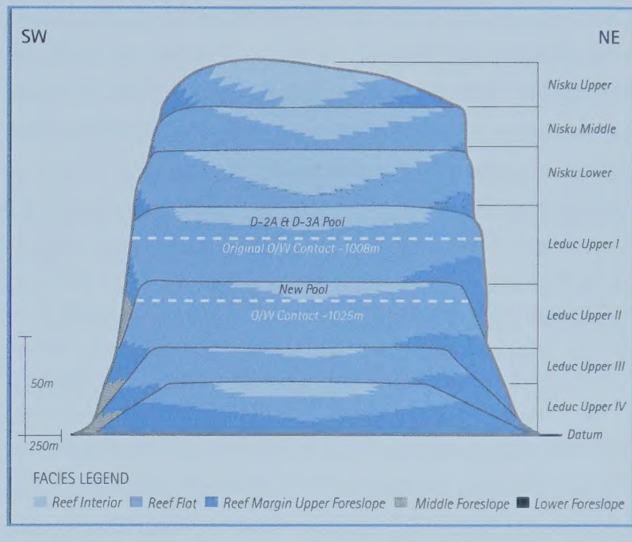
PROPERTY REVIEWS

Haynes, Alberta

The Haynes property is located approximately 30 kilometers east of Red Deer, Alberta. Case has an average working interest of about 95% in the production from 27 producing wells which are all flow lined into a central battery and which are essentially 100% operated by Case.



Haynes, Alberta



Haynes – Leduc and Nisku Schematic Stratigraphy

The Haynes property produces a sour, light (40° API), high quality oil and associated sour gas, which are separated from produced water at the main battery. The sales oil is delivered into a Koch pipeline at the battery and the natural gas is compressed at Case's main battery and delivered for processing into the Haynes Pipeline (40% owned by Case) which connects to the gathering system for the Nevis sour gas plant. Processed natural gas enters the Nova system at the outlet from the Nevis plant. The water that is removed from the effluent stream at Haynes is injected into a disposal well at the Haynes site. Fuel gas for the Haynes battery is obtained from 4 sweet shallow gas wells at Haynes in which Case has a working interest. The remaining sweet gas not used as fuel is sold on the spot market.

The Haynes facility processes sour gas that contains up to 20% hydrogen sulfide, which is an extremely toxic substance. Case takes considerable precautions on an ongoing basis to prevent accidental releases from the facility and to ensure that no harm or loss results to residents, company personnel, the environment or property. The Haynes facility has operated for more than 2000 days with no lost time due to injury. Case has received an industry supported "Certification of Recognition", for its proactive approach to Health, Safety and the Environment.

The Nisku and Leduc formations (D2 and D3) are the main productive zones at Haynes, specifically the "Haynes D-2A and D-3A" oil pool, which was discovered in 1968. Two Nisku wells drilled in 1993 to the south west of the Haynes D-2A and D-3A pool have been called the "Haynes D-2C" pool, but Case's 3-D seismic program in 2002 confirms that all the Haynes wells at that time were in one main pool.

The facilities at Haynes consist of a zero emissions oil battery with a capacity of 6,000 bbls/day of effluent processing, associated flow lines and artificial lift equipment, virtually all of which is 100% owned by Case. In addition, the Haynes facilities include two natural gas dehydrators and a sour gas compressor with a capacity of 5.3 mmcf/day, which is owned by Case as to 96.5%. Case also owns 40% of the 6" Haynes Pipeline that delivers natural gas from the Haynes battery to the Nevis Plant gathering system for Case and third parties. Case provides effluent processing, compression services, contract well operating services and accounting administration services for several third parties on a fee for service basis.

REVIEW OF OPERATIONS

Case's net production from the Haynes property in 2003 averaged 1,422 BOE/day consisting of 990 bbls/day of light sour crude oil, 117 bbls/day of natural gas liquids and 1,887 mcf/day of natural gas. Average production for December 2003 was 1,613 BOE/day from Haynes. In addition there is 385 bbls/day of behind pipe production that has been production tested and not produced or produced and suspended which can be easily brought on stream as the presently producing zones in those well bores decline in production and good production practice is approved for the new discovery wells.

During 2003 Case drilled 6 Nisku oil wells, 2 Belly River gas wells (1 well is currently standing, non producing), and 2 Glauconite gas wells at Haynes. Production from the shallow gas wells has declined rapidly and Case is re-evaluating the economics of further shallow gas drilling at Haynes. As a result of drilling the Nisku oil wells, Case has made two new pool Leduc discoveries at Haynes that will be targeted for further drilling during 2004.

Drilling activities at Haynes resulted in three New Pool discoveries in the Glauconite, firstly the 02/15-11-38-24W4 well, and secondly the 07-22-38-24W4M well. The third discovery well is 00/7-15-38-24W4, which tested 4.1 mmcf/day of raw gas on drill stem test and is expected to come on production at approximately 1 mmcf/day. This well is currently a Nisku producer, the Glauconite will be completed and the well will then be tied in as a dual producer in March, 2004. All three wells are confirmed by pressure data to be separate new pools.

Case intends to continue its drilling activities at Haynes during 2004. Case has recently commenced a three well drilling program, which it hopes to conclude before breakup. All three wells are Nisku infill wells and two of the wells are being drilled deeper to test new pools in the Leduc. Results of these three wells will be used to determine the further development of the property.

Planning is currently ongoing to re-enter, whipstock and barefoot complete two older wells in the pool. The technical reasons for the proposed operations are to address poor recovery from these original wells as a reult of damage believed to have occured while drilling, casing and completing the wells. If the new completion technique is successful, a number of additional recompletion opportunities can be tested using this technique.

Case is also evaluating the installation of high volume lift facilities in some of the older well bores where oil production has declined and water cuts have increased.

Case has identified significant upside potential on its Haynes lands including:

- Nine producing wells that have available a total of 17 Nisku/Leduc zones to recomplete uphole.
- Five proved plus three additional probable development drilling locations are currently assigned to the "D-2A and D-3A" oil pool. An additional four to eight locations are contingent on the specific pay intervals encountered in the next round of drilling.
- Two to four of the above locations in the development drilling program will also evaluate new and/or possibly extend the recent Leduc new pool discoveries.
- A significant land base to develop Belly River and Edmonton shallow gas.
- A significant land base to develop coal bed methane gas.

Brazeau River Area

Case is at an early stage of development of its Brazeau River Shallow Gas Project. Case identified the area as an excellent area to explore and exploit Edmonton and Belly River gas. Through proprietary hydrodynamic evaluation, Case has identified the area to be dominantly gas saturated for over 1800m of depth, through the Edmonton and Belly River zones. Numerous reservoirs exist in this thick section of stratigraphy from the Edmonton and Belly River zones. In this area there is significant oil and gas production from the zones of interest.

Case has identified a number of wells with by-passed pay in these shallow sands and has established a land base around these wells. Case has identified 4 re-entry opportunities with a 100% working interest. Case also has identified 2 new drilling opportunities with 100% working interest. To date Case has drilled and cased one well at 5-24-46-14W5. This well was an exploration location, drilled on a geological concept. The reservoir was encountered; the well proved the play concept of gas pervasive sands, but the zone was not capable of commercial production. A subsequent completion of an Edmonton sand in this well has resulted in a marginal gas well. Tie-in of this well awaits additional gas production in the proximate area.

A focused geographical technical evaluation of the area has resulted in the identification of opportunities deeper in the geologic section. Case intents to re-enter a well with by-passed pay in the Rock Creek shortly after breakup. Case intends to pursue further exploration and development activities in this area during 2004.

West Hazel, Saskatchewan

On February 28, 2003 Case disposed of its other heavy oil properties and reduced its interest in the West Hazel area of western Saskatchewan, (Twp 50, Rge 22W3) to a 25% interest in 2,292 acres of land, and a 25% interest in a 26.25% net profit interest in 40 acres, which are operated by Ranchgate Energy Inc.

During 2003 this property produced an average of 187 bbls/day of heavy oil from 15 wells in the Mannville group of formations. Average production for the month of December, 2003 was 55 bbls/day as most of the wells were suspended during that month while infill wells were being drilled and completed and these wells did not fully return to their pre-suspension production levels.

All wells utilize down hole screw pumps operated by gas engines and presently produce to single well batteries. Produced fluid from each well is treated in tanks on site from which oil and produced water are trucked to Husky for sale or disposal. Produced sand is flushed from the bottom of tanks and shipped to Baytex's Carruthers facility.

Case's lands are within the Lloydminister heavy oil accumulation, a discontinuous trend of Lower Cretaceous bitumen and heavy oil sand deposits extending from Athabasca through Cold Lake and Lloydminister into north central Saskatchewan. The Mannville Group varies from 150-200m in thickness and is divided into nine formations, of which three, the Waseca, Sparky and General Petroleum (GP) are or have produced on Case's lands at West Hazel.

In 2003 Case participated in an extensive 3-D seismic program at West Hazel and in the drilling of 5 (net 1.25) infill wells, which are now on production. As comman practice in the area, to assist in the drilling operations of the new wells, production from a number of the existing producing wells was suspended. Complications, resulted in these wells being shut in for an extended period of time. To date not all of that production has yet come back on stream. All five of the new wells are currently producing from the General Petroleum and or Sparky, and there is further potential zones to complete in the future.

Further development potential at West Hazel includes recompletion/workovers, completion of behind pipe zones, operating efficiencies and infill drilling opportunities.

In addition, potential for exploration exists on recently acquired crown lands in the area and a 2-D geophysical program is being planned to evaluate these lands, and offsetting crown land.

Case and its joint interest partners are evaluating four further infill drilling locations identified by the 3-D seismic program and are proceeding with the installation of water disposal facilities to reduce operating costs in this area.

RESERVES EVALUATION

An independent engineering evaluation of Case's oil and gas properties was conducted effective as at December 31, 2003 by Gilbert Laustsen Jung Associates Ltd. ("GLJ") in accordance with National Instrument 51-101. GLJ's Report on this evaluation is herein called the GLJ Report. For the purposes of properly understanding the reserve quantities and future net revenue data presented from GLJ's Report it is important to understand each of the following:

- The preparation date of this information is March 15, 2004.
- Reserve quantities are stated on a total company interest basis (before royalty burdens and including royalty interests) unless noted otherwise, to be consistent with prior disclosure.
- Reserve quantities and future net revenue amounts are based on GLJ's January 2004 price forecast the relevant data from which is presented below.
- BOE's may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

- The estimate of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.
- The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.
- In all cases, the finding and development cost is calculated by dividing the identified capital expenditures by the applicable reserves additions.

Additional reserves data and other oil and gas information will be filed and available on SEDAR at www.sedar.com in accordance with National Instrument 51-101.

Total Company Interest Reserves – Forecast Prices and Costs

The following table sets forth a summary of Case's total company interest reserves before deduction of royalty interests held by others and including royalty interests held by Case. These reserves are based on GLJ's forecast prices and costs effective January 1, 2004. These reserve volumes and associated future net revenues do not vary materially from the gross reserves required by National Instrument 51-101 that excludes royalty interests held by Case because Case does not hold any material royalty interests. Case's gross reserves required by National Instrument 51-101 and its net reserves after royalties, will be disclosed in the Reserves Data and other oil and gas information that will be filed on SEDAR at www.sedar.com.

Total Company Interest Reserves Summary – Forecast Prices and Costs

	Reserves Summary [1,2]								Estimated Future Net Cash Flow			
	Light Oil & NGL's (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		BOE @ 6:1 [3] (mboe)		Discounted at ($000's)			
Reserve Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	1,541	1,188	132	117	2,730	2,003	2,128	1,640	38,835	29,622	26,730	24,475
Proved Developed Non-Producing	476	410	228	205	1397	1,031	938	786	13,346	7,997	6,564	5,548
Proved Undeveloped	557	436	37	29	882	641	741	572	7,492	4,828	3,966	3,287
Total Proved	2,574	2,034	398	351	5,010	3,674	3,807	2,998	59,673	42,446	37,261	33,309
Probable	1,265	1,019	305	270	2,401	1,759	1,971	1,582	29,994	16,122	12,804	10,528
Total Proven + Probable	3,839	3,053	703	621	7,411	5,433	5,777	4,580	89,667	58,569	50,065	43,838

1. *Gross Reserves are the Corporation's interest including royalty interests before deduction of royalties*
2. *Net Reserves are the Corporation's interest including royalty interests after the deduction of royalties*
3. *Natural gas is converted to barrels of oil equivalent on the basis of 6 mcf of natural gas equals 1 barrel of oil equivalent. BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Commodities Price Forecast

The following table sets forth GLJ's January 1, 2004 forecast of commodity prices, currency exchange rate and inflation rate used in the preparation of the GLJ Report.

Historical and Forecast Prices

	WTI Crude Oil ($US /bbl)	Edmonton Crude Oil ($Cdn. /bbl)	Bow River Crude Oil Stream at Hardisty ($Cdn./bbl)	Natural Gas at AECO ($Cdn./ mmbtu)	Natural Gas Liquids ($Cdn./bbl) Edmonton Propane	Edmonton Butane	Edmonton C5+	Currency Exchange Rate $US/$Cdn.	Inflation Rate %
2003 Actual	**30.96**	**43.51**	**32.01**	**6.66**	**32.01**	**34.01**	**44.01**	**0.721**	**2.8**
GLJ January 1, 2004 Price Forecast									
2004	29.00	37.75	26.75	5.85	26.75	28.75	38.75	0.75	1.5
2005	26.00	33.75	25.75	5.15	21.75	23.75	34.25	0.75	1.5
2006	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
2007	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
2008	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
2009	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
2010	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
2011	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
2012	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
2013	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
2014	25.00	32.50	26.00	5.00	20.50	22.50	33.00	0.75	1.5
Escalate thereafter at	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr	1.5%/yr		1.5/yr

Net Asset Value – Forecast Prices and Costs

The following tables set forth the net asset value of Case's shares at December 31, 2003 based upon the future net revenues estimated by GLJ using GLJ's forecast prices and costs.

Net Asset Value at December 31, 2003 using GLJ Forecast Prices and Costs

($)	Total Proved	Proved + Probable
Estimated net future revenues from GLJ Report *(discounted at 10%)*	42,446,000	58,569,000
Land and seismic *	1,500,000	1,500,000
Indebtedness	(6,125,000)	(6,125,000)
Net asset value	37,821,000	53,944,000
Net asset value per share (60,000,179 shares)	$0.63	$0.90

* *Based on internal estimates of $75 per acre for undeveloped land and $600,000 for seismic.*

Total Company Interest Reserves – Constant Prices and Costs

The following table sets forth Case's total company interest reserves before deduction of royalty interests held by others and including royalty interests held by Case. These reserves are based on GLJ's constant prices and costs which uses WTI of $US 32.52/bbl, $Cdn. 40.81/bbl for light sweet oil at Edmonton and $Cdn. 6.09/mmbtu for natural gas at AECO. These reserve volumes and associated future net revenues do not vary materially from the gross reserves that excludes royalty interests held by Case because Case does not hold any material royalty interests. Case's gross reserves required by National Instrument 51-101 and its net reserves after royalties, will be disclosed in the Reserves Data and other oil and gas information that will be filed on SEDAR at www.sedar.com.

Total Company Interest Reserves Summary – Constant Prices and Costs

	Reserves Summary [1,2]								Estimated Future Net Cash Flow			
	Light Oil + NGL's (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		BOE @ 6:1 [3] (mboe)		Discounted at ($000's)			
Reserve Category	Gross	Net	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
Proved Developed Producing	1,562	1,198	133	117	2,743	2,013	2,152	1,651	50,445	37,138	33,119	30,037
Proved Undeveloped/Non-Producing	476	410	241	216	1,397	1,031	951	797	18,345	10,907	8,901	7,473
Proved Developed Non-Producing	540	418	37	29	875	635	724	553	11,099	7,486	6,278	5,321
Total Proved	2,579	2,026	411	362	5,015	3,678	3,826	3,001	79,888	55,531	48,299	42,830
Probable	1,274	1,020	311	275	2,404	1,760	1,986	1,588	41,290	21,881	17,295	14,164
Total Proven + Probable	3,854	3,045	722	637	7,419	5,438	5,812	4,589	121,178	77,412	65,594	56,994

1. *Gross Reserves are the Corporation's interest including royalty interests before deduction of royalties*
2. *Net Reserves are the Corporation's interest including royalty interests after the deduction of royalties*
3. *Natural gas is converted to barrels of oil equivalent on the basis of 6 mcf of natural gas equals 1 barrel of oil equivalent. BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Net Asset Value – Constant Prices and Costs

The following tables set forth the net asset value of Case's shares at December 31, 2003 based upon the future net revenues estimated by GLJ using constant prices and costs – WTI of $US 32.52/bbl, light sweet oil at Edmonton at $Cdn 40.81/bbl and natural gas at AECO at $Cdn 6.09/mmbtu.

Net Asset Value at December 31, 2003 using Constant Prices and Costs

	Total Proved	Proved + Probable
Estimated net future revenues from GLJ Report (discounted at 10%)	55,531,000	77,412,000
Land and seismic **	1,500,000	1,500,000
Indebtedness	(6,125,000)	(6,125,000)
Net asset value	50,906,000	72,787,000
Net asset value per share (60,000,179 shares)	$0.85	$1.21

** *Based on internal estimates of $75 per acre for undeveloped land and $600,000 for seismic*

RESERVES RECONCILIATION

Gross Reserve Reconciliation

The following table sets forth the reconciliation of Case's total company interest proved and probable reserves as at December 31, 2003.

	Light Oil + NGL's (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		BOE @ 6:1 (mboe)	
	Proved	Proved + Probable*	Proved	Proved + Probable*	Proved	Proved + Probable*	Proved	Proved + Probable*
Reserves at December 31, 2002	2,892	3,354	562	760	4,856	5,805	4,263	5,081
Exploration discoveries	–	–	–	–	–	–	–	–
Drilling Extensions	380	617	231	419	1,250	1,640	819	1,310
Improved Recovery	207	483	–	–	–	–	207	483
New Evaluation Standards	–	–	–	–	–	–	–	–
Technical Revisions	(392)	(85)	(60)	(42)	976	2,278	(289)	252
Acquisitions	–	–	–	–	–	–	–	–
Divestments	(100)	(117)	(267)	(366)	(1,296)	(1,536)	(583)	(739)
Production	(413)	(413)	(68)	(68)	(776)	(776)	(610)	(610)
Reserves at December 31, 2003	**2,574**	**3,839**	**398**	**703**	**5,010**	**7,411**	**3,807**	**5,777**

* *Reserves at the end of 2002 were estimated in accordance with National Policy 2-B. Accordingly, for purposes of comparison with the reserves estimated in accordance with National Instrument 51-101, the previously denoted "established" reserves (proved plus 50% probable) are used from Case's engineering evaluation as at December 31, 2002.*

Finding and Development Costs

The following table sets forth Case's finding and development costs for the last three fiscal years.

Finding and Development Costs:

	2003		2002		2001		AVG 3 Years	
	Proved	Proved + Probable	Proved	Proved + Probable	Proved	Proved + Probable	Proved	Proved + Probable
Total exploration and development costs incurred	**14,345,710**	**14,345,710**	11,196,196	11,196,196	4,109,413	4,109,413	29,651,319	29,651,319
Change in future development costs								
Prior year	**(5,350,000)**	**(5,585,000)**	(480,000)	(997,000)	(380,000)	(773,000)	(6,210,000)	(7,355,000)
Current Year	**7,935,000**	**10,359,000**	5,350,000	5,585,000	480,000	997,000	13,765,000	16,941,000
	2,585,000	**4,774,000**	4,870,000	4,588,000	100,000	224,000	7,555,000	9,586,000
Total exploration and development for F&D	**16,930,710**	**19,119,710**	16,066,196	15,784,196	4,209,413	4,333,413	37,206,319	39,237,319
Reserve additions, including revisions excluding acquisitions/dispositions *(MBOE) (6:1)*	**737**	**2,045**	2,298	2,551	102	28	3,137	4,624
Average finding and development cost per BOE	**$ 22.97**	**$ 9.35**	$ 6.99	$ 6.19	$ 41.27	$ 154.76	$ 11.86	$ 8.49
Acquisition expenditures net of disposition proceeds	**(5,806,767)**	**(5,806,767)**	10,070,040	10,070,040	4,052,674	4,052,674	8,315,947	8,315,947
Reserve additions, from acquisitions net of dispositions *(MBOE) (6:1)*	**(583)**	**(739)**	1,631	2,030	411	523	1,459	1,814
Avg. acquisition/disposition cost/proceeds per BOE	**$ 9.96**	**$ 7.86**	$ 6.17	$ 4.96	$ 9.86	$ 7.75	$ 5.70	$ 4.58
Total finding, development and net acquisition costs ("FD&A")	**11,123,943**	**13,312,943**	26,136,236	25,854,236	8,262,087	8,386,087	45,522,266	47,553,266
Reserve additions, for FD&A *(MBOE) (6:1)*	**154**	**1,306**	3,929	4,581	513	551	4,596	6,438
Average FD&A cost per BOE	**$ 72.23**	**$ 10.19**	$ 6.65	$ 5.64	$ 16.11	$ 15.22	$ 9.90	$ 7.39

* *Reserves for 2003 were determined in accordance with National Instrument 51-101. Reserves for 2001 and 2002 were determined in accordance with National Policy 2-B. The Reserves for these years are therefore not directly comparable. The table displays for Proved + Probable Reserves for 2001 and 2002, the previously denoted "established reserves" (proved plus 1/2 probable) determined in accordance National Policy 2-B which are also used in determining the three year average.*

Management's Discussion & Analysis

The following discussion and analysis is management's assessment of the historical financial and operating results of Case Resources Inc. (the "Corporation" or "Case") and should be read in conjunction with the audited comparative consolidated financial statements of the Corporation for the year ended December 31, 2003, together with the notes thereto all of which has been prepared in accordance with Canadian generally accepted accounting principles. Readers should be aware that the following discussion and analysis relates in part to the 2002 fiscal year. The date of this Management's Discussion and Analysis is March 18, 2004.

Additional information relating to the Corporation, including the latest Annual Information Form filed by the Corporation, is available on SEDAR at www.sedar.com.

FORWARD LOOKING STATEMENTS

This disclosure includes forward-looking statements and assumptions respecting the Corporation's strategies, future operations, expected financial results, financing sources, commodity prices, costs of production and quantum of oil and natural gas reserves and discusses certain issues, risks and uncertainties that can be expected to impact on any of such matters

By their nature, forward-looking statements are subject to numerous risks and uncertainties that can significantly affect future results. Actual future results may differ materially from those assumed or described in such forward-looking statements as a result of the impact of issues, risks and uncertainties whether described herein or not, which the Corporation may not be able to control. The reader is therefore cautioned not to place undue reliance on such forward-looking statements.

The Corporation disclaims any intention or obligation to update or revise these forward-looking statements, as a result of new information, future events or otherwise.

NON-GAAP MEASURES

Included in this Management's Discussion and Analysis and in the Corporation's Annual Report for 2003 are references to terms commonly used in the oil and gas industry, such as cash flow, cash flow per share, netback and cash flow netback.

Cash flow, as discussed in this Management's Discussion and Analysis and in the Corporation's Annual Report for 2003, appears as a separate caption on the Corporation's Consolidated Statements of Cash Flows and is reconciled to net earnings. In the Corporation's disclosure, netback denotes petroleum and natural gas revenue less royalties (net of ARTC) and less operating expenses. Cash flow netback as used herein denotes net earnings plus future income tax expense (less any recovery), depletion and depreciation expense and stock option compensation expense.

These terms are not defined by Generally Accepted Accounting Principles and consequently, these are referred to as non-GAAP measures. A reader should be cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used.

MANAGEMENT'S DISCUSSION AND ANALYSIS

SELECTED ANNUAL INFORMATION

The following table sets forth a summary of the financial highlights of the Corporation for the years ended December 31, 2003, 2002 and 2001.

Years Ended December 31 *(Can $)*	2003	2002	2001
Petroleum and natural gas revenue	**23,352,055**	12,272,209	3,489,522
Total revenues, net of royalties	**17,948,721**	9,632,214	3,179,788
Cash flow from operations	**11,761,467**	4,649,299	102,830
Basic per share	**0.20**	0.09	0.01
Diluted per share	**0.19**	0.09	0.01
Net income (loss)	**6,740,299**	2,597,687	(9,065,878)
Basic per share	**0.11**	0.05	(0.49)
Diluted per share	**0.11**	0.05	(0.49)
Capital expenditures, net	**8,567,022**	21,354,031	8,166,387
Total assets	**28,019,778**	24,080,759	3,365,534
Working capital deficiency	**1,392,740**	811,355	623,928
Production loan	**4,732,524**	7,458,345	–
Total debt	**6,125,264**	8,269,700	623,928
Shareholders' equity	**18,901,131**	12,767,059	1,385,849
Average daily production *(boe at 6:1)*	**1,671**	1,073	322
Common shares outstanding, end of period			
Basic	**60,000,179**	60,792,679	32,198,218
Weighted average common shares outstanding			
Basic	**60,295,684**	54,768,235	18,567,707
Diluted	**61,673,113**	54,785,696	18,567,707

The 2001 year reflects the substantially different size and quality of the Corporation's asset base prior to the acquisition by the Corporation of the Haynes property on February 28, 2002. The significant loss disclosed for 2001 is attributable to the ceiling test write-downs that occurred in 2001 which have been previously disclosed and discussed.

MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS

The financial results of the Corporation have been and will continue to be significantly affected by a number of corporate financing and property transactions that were closed in 2003 and 2002. These transactions are summarized below:

1. On February 28, 2002, the Corporation closed a $12,000,000 (before adjustments) acquisition of light oil and natural gas producing properties in central Alberta. The acquisition had an effective date of November 1, 2001 for the purpose of determining the final purchase price. In conjunction with this acquisition some miscellaneous interests were removed from the acquisition by the exercise of rights of first refusal by third parties. As a result the Corporation purchased the central Alberta properties for a total of $10,962,000, and concurrently sold some of the properties for $1,213,000 resulting in a net acquisition price of approximately $9,749,000. In order to finance the acquisition price, the Corporation issued 24,999,999 common shares at $0.30 per share pursuant to a private placement on February 14, 2002 for gross proceeds of $7,500,000 (net proceeds of approximately $7,004,632 after a commission of $375,000 and related costs, see Note 6(c) to the consolidated financial statements) and increased its revolving production loan facility.
2. On October 31, 2002, the Corporation completed a private placement of 3,394,462 common shares at a price of $0.65 per share for gross proceeds of $2,206,400 (net proceeds of $2,115,471 after related costs).

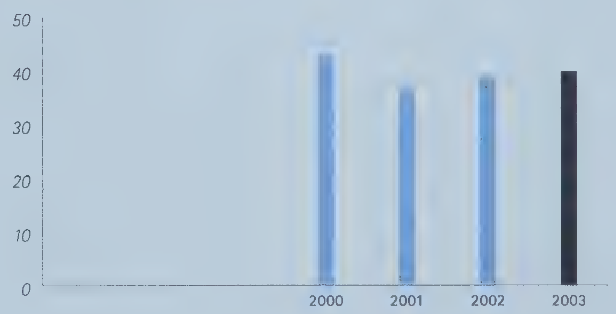
3. On December 19, 2002, the Corporation completed a private placement of 200,000 common shares on a flow through basis at a price of $1.00 per share for gross proceeds of $200,000 (net proceeds of $199,050 after related costs).
4. During 2002, the Corporation disposed of some minor none-core properties in the Acheson and Three Hills areas and acquired additional working interests in the Haynes area from three other joint interest owners.
5. In February, 2002 the Corporation increased its available credit facility to $5,975,000, in July, 2002, the Corporation increased its available credit facility to $7,000,000, in September, 2002 the Corporation increased its available credit facility to $8,500,000 and in December, 2002 the Corporation increased its available credit facility to $9,700,000.
6. On February 28, 2003, in two separate transactions, the Corporation disposed of approximately one half of its petroleum and natural gas properties located mainly in the West Hazel area of Saskatchewan for net proceeds of $2,340,697. Both transactions were effective January 1, 2003 for purposes of determining the purchase price. These consolidated financial statements include the revenue and expenses from the properties up to and including the closing of the transactions on February 28, 2003.
7. On April 16, 2003 the Corporation disposed of most of its miscellaneous non-core petroleum and natural gas properties located mainly in southern Alberta for net proceeds of $3,745,649. The transaction was effective April 16, 2003 for purposes of determining the purchase price. These consolidated financial statements include the revenue and expenses from these properties up to and including the closing of the transaction on April 16, 2003.
8. During the second quarter of 2003 the Corporation purchased 792,500 of its own common shares through its previously announced Normal Course Issuer Bid. The total cash consideration paid for the common shares including commissions was $615,466 for an average price of $0.78 per common share. The common shares have been cancelled.
9. In July, 2003, the Corporation increased its credit line to $13,000,000 from $9,700,000 at the end of the prior year. The next annual review date for this credit facility is May 31, 2004.

OVERALL PERFORMANCE

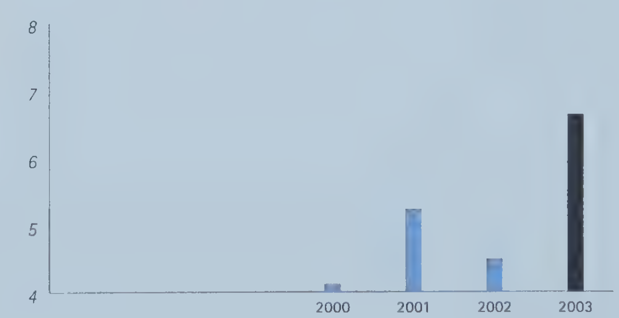
The primary factors affecting the Corporation's overall performance were the increased production levels achieved during 2003 coupled with high commodity prices. Both of these matters are discussed in further detail below. The main industry factors that affect Case's performance is the increased level of activity in the industry that increases Case's costs of acquiring undeveloped lands, producing properties and oilfield services. This also has the affect of making the terms of access to drilling opportunities less favourable to Case and reduces its capability to access quality oilfield services on a timely basis.

These factors have affected Case's ability to acquire the new core areas that it has been seeking over the last two years on terms it considers reasonable. Case has therefore pursued a longer term strategy to develop a new core area by land acquisition and exploration activities in an area where Case has no existing production base or infrastructure. Case also continues to actively pursue opportunities to develop new core areas through acquisition or joint venture.

Crude Oil & Liquids Price *($/bbl)*



Natural Gas Price *($ mcf)*



LIQUIDITY

The Corporation had a working capital deficit of $1,392,740 and $4,732,524 of current bank debt at December 31, 2003. This is a 72% increase from the prior year working capital deficit of $811,355 and a 37% decrease in the amount of bank debt as compared to the prior year amount of $7,458,345. The combination of these changes results in an overall reduction of total debt. This reduction is a result of the funding of the Corporation's capital expenditure program during 2003 ($14,701,868) along with the re-purchase of common shares pursuant to its Normal Course Issuer Bid ($615,466) entirely from both the internally generated funds ($11,761,467) and the proceeds of property dispositions ($6,134,846).

The Corporation has traditionally financed its oil and gas operations primarily through the reinvestment of the Corporation's cash flow from operations, proceeds from bank debt and equity financings. The Corporation expects to be able to continue to raise additional equity and debt financing sufficient to meet both its short-term and long-term growth requirements in the current environment.

The Corporation expects to generate sufficient cash from operations and to have sufficient available credit to fund its budgeted capital expenditure program for 2004.

The main components of the budgeted capital expenditure program for 2004 include the drilling of 6 Nisku/Leduc oil wells at Haynes, plus two sidetracks from existing well bores and various workovers and facility upgrades for a total capital expenditure at Haynes of approximately $10,000,000. In addition the Corporation has budgeted to spend approximately $5,000,000 on exploration activities unrelated to the Haynes area. In total, the capital expenditure program for 2004 is approximately $15,000,000. Although some of that capital spending has already begun, the Corporation has no commitments outstanding that require it to expend the budgeted capital.

The Corporation has not budgeted for any acquisitions during 2004 but management intends to diversify the Corporation's asset base into other areas during 2004 and therefore the Corporation is constantly reviewing potential property acquisitions, joint venture opportunities, and corporate acquisitions with the intention of completing such a transaction. Management is confident that in the current environment, the Corporation is capable of raising sufficient equity and/or debt financing to fund one or more of these transactions.

The major risk factors affecting the Corporation's liquidity are commodity prices for light oil and natural gas and to a much lesser degree heavy oil and the uncertainty of achieving planned production from the expenditure of capital on development and exploration projects. The commodity price environment is currently very strong with WTI spot oil prices exceeding US$35.00. However, the commodity price is unpredictable and a significant reduction in commodity prices for light oil or natural gas would affect the Corporation's ability to fund capital expenditures from internally generated funds. The Corporation does not presently have any commodity price or exchange rate hedges or fixed price sales contracts in place and all of its production is sold at spot prices. The Corporation may from time to time fix the commodity prices or currency exchange rates for future periods on some of its production. See the disclosure under the heading entitled "PETROLEUM AND NATURAL GAS REVENUE".

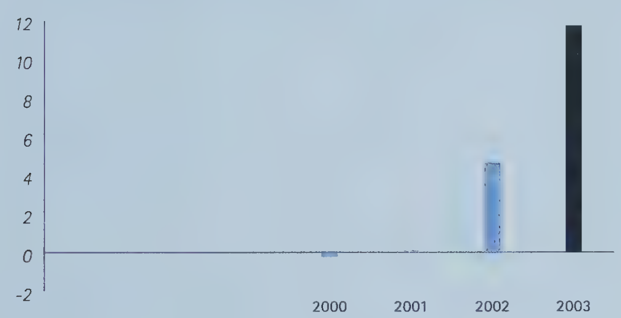
The Corporation manages the risks associated with its development and exploration projects by maintaining highly qualified technical and operations people to identify and carefully evaluate the Corporation's opportunities. The Corporation's 2004 capital spending is primarily focussed on the Haynes property with approximately 65% of the 2004 capital budget being allocated for that area. Should the capital spending on this property not produce anticipated results, management will have to review the remaining capital expenditure program to ensure the costs of the projects it proceeds with will be within the financial resources available from its cash flow, debt capacity, proceeds, if any, from disposition of non-core properties, and additional equity financing capability at that time.

The management of Case has a proven track record of being able to raise substantial amounts of equity. Management anticipates that in order for the Corporation to grow substantially over the next few years new equity will be required for significant projects and acquisitions.

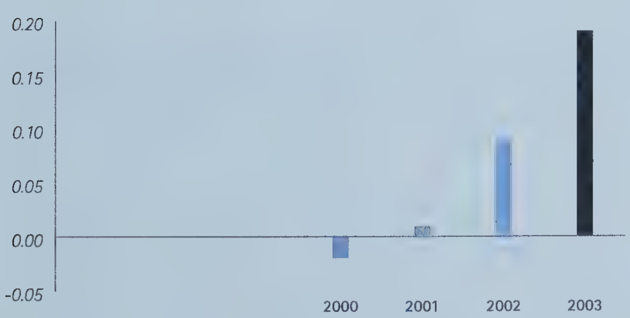
Cash Flow from Operations

The Corporation's cash flow from operations of $11,761,467 during the year ended December 31, 2003 is an increase of 153% over the cash flow from operations of $4,649,299 in 2002. This increase in cash flow was due primarily to increased light oil and natural gas sales volumes resulting from the development of the Haynes property acquired on February 28, 2002. The Haynes property averaged 1,422 boe per day in 2003 and is included for a full 12 months compared to averaging 562 boe per day during 2002 and included for only 10 months. Prices also had an impact as we averaged $38.04 per boe for 2003 as compared to $31.14 per boe for 2002, an increase of 22%. The increase resulting from these two factors was mitigated partially due to the sale of a portion of the heavy oil properties and most of the non-core central Alberta properties in early 2003.

Cash Flow *($ millions)*



Cash Flow per Share *($)*



The two key factors currently influencing the Corporation's cash flow from operations are the level of commodity production and the commodity prices. Although the impact on the Corporation of interruptions in production from individual wells is less than would have been the case during 2001, it is similar to the case during 2002 in that the Corporation still relies on some relatively high volume oil wells and should an uncontrollable event occur which adversely affects any of those high volume wells, it may significantly affect cash flow.

The Haynes reservoir has a strong bottom water drive that could result in one or more wells watering out prematurely. Drainage patterns in the pool are complex and may be further complicated by the fact that produced water is disposed of back into the water leg of the reservoir. It is possible that infill wells may be drilled into parts of the reservoir that have already been drained or swept. During 2003, the Haynes field experienced increased water cuts in several wells and higher than expected water cuts and decline rates from 4 of the infill wells drilled in 2003.

Case has encountered localized secondary gas caps that have resulted from pressure depletion in the pool over the last 40 years. Case's production practice is to blow down these localized gas caps as we believe that no detrimental long-term effects will result because the drive mechanism in the pool is dominated by the strong bottom water drive. Insufficient production history exists at this time to conclusively determine the long-term impact of this operating strategy. As a result of this strategy, Case was producing natural gas from a localized gas cap in the Nisku zone in the 15-11 well bore and concurrently producing light oil from the Leduc zone below. The Nisku zone, was being produced with the expectation it would eventually begin to produce oil as the localized gas cap was depleted. However, recently the Nisku zone began producing increased water and some oil and consequently, production from this zone was suspended so that the oil production from the Leduc zone below would not be jeopardized. The Nisku zone will not likely be re-activated until the Leduc zone has been depleted. This suspension occurred prior to the recent completion of the Corporation's engineering evaluation performed effective December 31, 2003 and accordingly both reserves and production associated with this suspended zone were excluded from that evaluation until the timing of reactivation of this zone can be established.

In addition, the Corporation's ability to produce its sour wells at Haynes, which comprise approximately 90% of its current production, is dependant upon its continued ability to process its production through its own battery located at Haynes and its ability to transport and process the associated sour solution gas at the Nevis Plant which is owned and operated by a third party. Any significant outage at either of these facilities would have a material adverse effect on the Corporation's production volumes and resulting cash flows. The Corporation carries business interruption insurance to mitigate these processing plant risks but an extended outage exceeding 6 months would significantly and adversely affect the Corporation's cash flows and business plan.

Sensitivity Analysis

The following table sets forth management's estimate of the sensitivity of the expected cash flow to be generated by the Corporation during the period January 1, 2004 through to December 31, 2004 based on the budget approved by the Corporation's Board of Directors, which includes numerous assumptions. The budget includes a significant capital expenditure program on the Haynes field of approximately $10,000,000 and includes approximately $5,000,000 of exploration related expenditures unrelated to the Haynes area. The 2004 budget does not contemplate any acquisitions or dispositions.

Sensitivity Analysis on 2004 Budget

Factor	2004 Budget	Variance in Factor	Variance in Cash Flow Cdn.$
WTI oil price	US $31.84/bbl	US $1.00/bbl	510,000
Natural gas spot price	Cdn. $6.08/mcf	Cdn. $0.20/mcf	84,000
Lloyd blend differential	US $10.00/bbl	US $1.00/bbl	60,000
Cdn.$/US$	$1.3298	Cdn. $0.01	122,000
Prime rate	4.50%	1.0%	78,000

Bank Debt

As a result of the dispositions in early 2003, the production loan decreased from $7,458,345 at the end of 2002 to $4,732,524 at the end of 2003. The Corporation's working capital deficit, however, increased to $1,392,740 at the end of 2003 from $811,355 at the end of the prior year. The resulting total debt therefore decreased from $8,269,700 to $6,125,264 or 26%. The Corporation currently has in place a $13,000,000 demand revolving production credit facility with a major lending institution. Outstanding indebtedness bears interest at the institution's prime lending rate plus 0.25%.

Management's intent is to work closely with its credit facility provider to increase the credit facility based upon the reserves resulting from the prior year's development program and based upon the increase in proved producing reserves expected to result from the 2004 capital expenditure program at Haynes.

OUTSTANDING SHARE DATA

The common shares of Case trade on the Toronto Stock Exchange under the symbol "CAZ". The following table summarizes the common shares issued during early 2004, 2003 and 2002, which are the only class of shares outstanding.

	Common Shares
Balance at December 31, 2001	32,198,218
Exercise of Options	–
Private Placements	28,594,461
Balance at December 31, 2002	60,792,679
Exercise of Options	–
Private Placements	–
Repurchase of common shares	(792,500)
Balance at December 31, 2003	60,000,179
Exercise of Options	58,333
Private Placements	–
Balance at March 18, 2004	60,058,512

For details of past issuances of common shares see the disclosure under the heading "MAJOR TRANSACTIONS AFFECTING FINANCIAL RESULTS " and under Note 6 of the December 31, 2003 consolidated financial statements.

RESULTS OF OPERATIONS

Petroleum and Natural Gas Revenue

Petroleum and natural gas revenue for the year ended December 31, 2003 was $23,352,055, which represents a 90% increase over the $12,272,209 realized in 2002. This increase in revenue is primarily a result of the impact on the production from the Haynes area development which resulted in an average production rate of 1,422 boe per day for the Haynes area for 2003 compared to only 562 boe per day in 2002. Average daily production for the year ended December 31, 2003 was 1,671 boe per day as compared to 1,073 boe per day realized for the same period in 2002, which is a 56% increase. Another factor contributing to the increase in petroleum and natural gas revenue was increased prices for all commodities, as noted in the table below. Approximately 68% of the Corporation's average annual production was light oil and natural gas liquids, 11% was heavy oil and 21% was natural gas during the 2003 fiscal year.

The following table details Case's petroleum and natural gas revenue, production and sales prices by category for its two most recently completed fiscal periods:

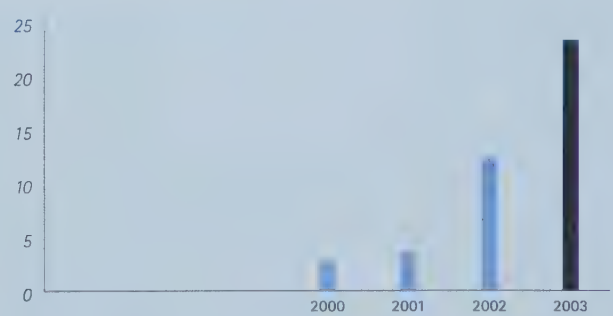
Petroleum and Natural Gas Revenue

	2003			2002		
	Total Revenue $	Average Daily Production	Average ($/unit)	Total Revenue $	Average Daily Production	Average ($/unit)
Light oil *(bbls)*	14,673,010	1,006	39.98	7,633,872	532	39.34
Heavy oil *(bbls)*	1,639,616	185	24.22	2,570,363	348	20.23
Natural gas *(mcf)*	5,152,018	2,126	6.64	1,397,618	853	4.49
Natural gas liquids *(bbls)*	1,730,052	125	37.85	591,310	51	31.82
Total petroleum and natural gas sales *(boe)*	23,194,696	1,671	38.04	12,193,163	1,073	31.14
Royalty revenue	157,359		0.26	79,046		0.20
Total petroleum and natural gas revenue	23,352,055		38.30	12,272,209		31.34

The price the Corporation receives for its crude oil depends on a number of factors, including U.S. dollar oil prices, the U.S./Canadian dollar exchange rate, and transportation and product quality differentials. Case regularly considers managing the risk associated with fluctuating U.S. dollar oil prices and the U.S./Canadian dollar exchange rate. In order to manage the risk the Corporation may enter into forward sale contracts, U.S. dollar oil price hedges and/or forward foreign exchange contracts.

The Corporation currently has no commodity price contracts or other hedge type contracts but had entered into a forward sale for the 2003 calendar year which fixed a price of Cdn. $24.87 for Light Lloyd Blend at Hardisty on a volume of 100 bbls/d of heavy oil. In the prior year, from January 1 to December 31, 2002 the Corporation sold forward 150 bbls/d of heavy oil at a WTI price of Cdn. $36.94 and at a Lloyd Blend at Hardisty differential of US$9.60. For the same period, the Corporation sold forward 50 bbls/day of heavy oil at a price of $Cdn. $32.21 and a Light Lloyd Blend differential of US$7.20.

Revenue *($ millions)*



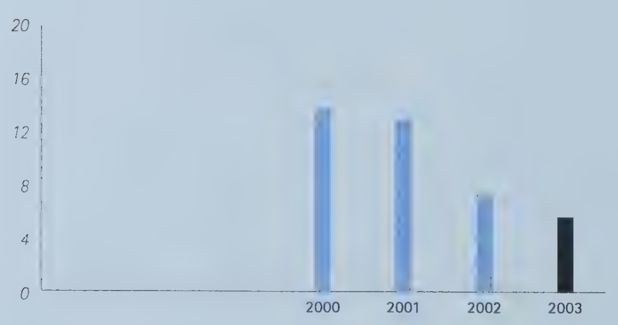
Royalties and ARTC

Royalties, net of ARTC, in the year ended December 31, 2003 were $5,407,216, which represents a 104% increase from the $2,647,660 incurred in 2002. This increase is primarily a result of the production increase from the Haynes property development in late 2002 and during all of 2003 and increased commodity prices as discussed above. The average royalty rate increased slightly from 22% in 2002 to 23% in 2003 mainly due to the Haynes property, which averaged 24% for 2003. The Haynes property accounted for almost 92% of the total royalties in 2003.

Operating costs

Operating costs in the year ended December 31, 2003 were $3,394,798, which is a 20% increase over the $2,823,502 incurred in 2002. This increase is primarily a result of the increased production due to the Haynes area development in late 2002 and during 2003. The operating costs at Haynes are mitigated by the effect of third party revenues Case receives for processing production for others and from its 40% non-operated interest in the Haynes Pipeline. On a per unit basis, operating costs decreased approximately 23% in 2003 to $5.57 per boe from $7.21 per boe in 2002. The lower unit costs were primarily a result of increased production providing economies of scale at the Haynes property, which averaged $4.76 per boe as compared to $4.96 per boe for 2002. The Haynes property accounted for 73% of the total operating costs in 2003.

Operating Costs *($/boe)*



General and Administrative Expense

General and administrative costs in the year ended December 31, 2003 were $2,628,722, which represents a 39% increase over the $1,892,176 incurred in 2002. This increase is due primarily to increased employee compensation associated with the increased levels of activity of the Corporation. On a per unit basis, general and administrative costs decreased approximately 11% in the current period to $4.32 per boe from $4.83 per boe in 2002, primarily as a result of increased production due to the Haynes property development. The components of G and A are as follows:

General and Administrative Expense

Years Ended December 31 *(thousands)*	2003	2002
Salaries, fees and consultants	**$2,794**	$1,776
Other	**937**	606
Cash G + A expense gross	**3,731**	2,382
Overhead recoveries	**(220)**	(145)
Capitalized overhead	**(891)**	(345)
Cash G + A expense net	**2,620**	1,892
Stock option compensation expense*	**9**	–
G + A expense net	**$2,629**	$1,892
Cash G + A expense per BOE	**$4.30**	$4.83
G + A expense per BOE	**$4.32**	$4.83

* *The stock option compensation expense is a non-cash item.*

Interest Expense

Interest expense in the year ended December 31, 2003 decreased to $142,551 from the prior year interest expense of $212,461. This decrease is due primarily to the property dispositions in early 2003, which reduced the average debt over the 2003 calendar year as compared to the prior year.

Depletion and Depreciation Expense

Depletion and depreciation expense (which includes the amortization of future site restoration costs) in the year ended December 31, 2003 was $4,564,929, which represents a 76% increase over the $2,587,242 incurred in 2002. This increase is due primarily to the increased production from the Haynes property development and associated capital spending. On a per boe basis depletion and depreciation increased from $6.61 per boe in 2002 to $7.49 per boe in 2003, primarily due to the 2003 finding and development costs for proved reserves being greater than the prior year depletion rate. As a result of the higher finding and development costs incurred

during the latter part of 2003, the Corporation expects future depletion and depreciation expense to increase by approximately 20% until lower cost reserves are added.

Provision for future site restoration costs

Site restoration expense (included in the depletion and depreciation expense above) in the year ended December 31, 2003 was $381,928, which represents a 123% increase over the $171,000 incurred in 2002. The increase is due primarily to the abandonment liabilities relating to the Haynes property. Certain old well bores were abandoned in 2003 at Haynes, which resulted in increased costs that were allocated directly to the site restoration expense account as compared to the normal amortization based on a unit of production method. On a per boe basis the amounts are $0.63 per boe for 2003 and $0.44 per boe for 2002.

Petroleum and Natural Gas Properties Ceiling Test

The Corporation follows the full cost method of accounting that requires the Corporation to apply a quarterly ceiling test to ensure that capitalized costs do not exceed the estimated value of future net revenues from the production of proved reserves less certain indirect costs associated with such production.

The Corporation conducted a ceiling test calculation at December 31, 2003. The sales prices, in Canadian dollars, at the wellhead used for the ceiling test were $38.31 per barrel for light oil, $21.56 per barrel for heavy oil and $6.40 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation is not required to write-down its petroleum and natural gas properties.

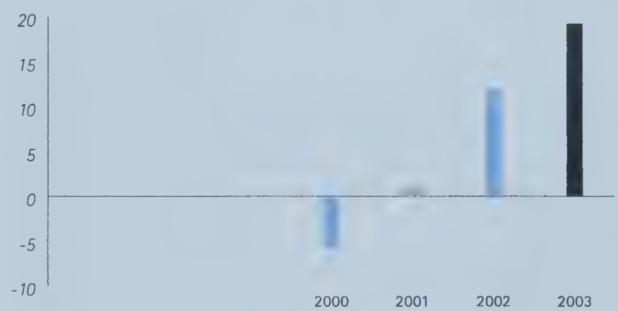
Effective January 1, 2004, the Corporation is required to perform a ceiling test using the new accounting guideline (AcG-16 oil and gas accounting - full cost) calculation as at January 1, 2004. The Corporation performed the required ceiling test calculation and no write-down is required. See the disclosure under the heading "CHANGES IN ACCOUNTING STANDARDS".

Taxes

The Corporation did not pay any income taxes in the twelve-month period ending December 31, 2003 or 2002. However the Corporation was required to pay cash taxes totalling $30,422 (2002 - $54,776). Of these amounts $30,422 (2002 - $26,000) related to the Federal Large Corporations tax and the Corporation paid $NIL (2002 - $28,776) in current taxes relating to Part XII.6 tax. This tax is a function of the time elapsed from the time resource expenditures are renounced to investors to the time at which the resource expenditures are actually incurred by the Corporation.

The Corporation recorded a future income tax expense of $447,000 (2002 - a recovery of $535,630) in its 2003 fiscal year. The Corporation has utilized all of its income tax benefits from prior periods and will continue to record future income tax expense in 2004.

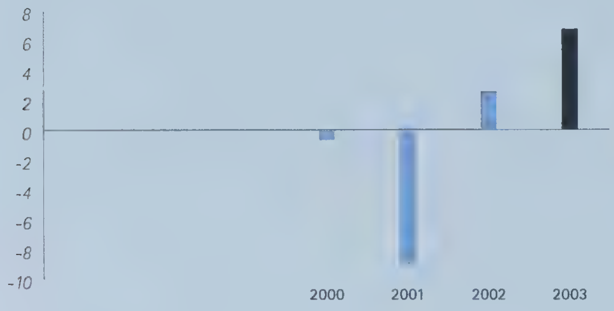
Cash Flow Netbacks *($/boe)*



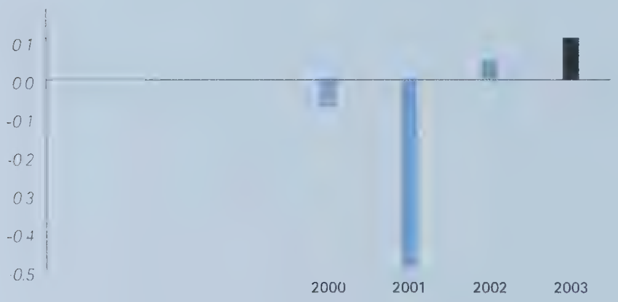
Net Earnings and Cash Flow from Operations

The Corporation recorded net earnings of $6,740,299 in the year ended December 31, 2003 compared to net earnings of $2,597,687 realized in 2002 for a 159% increase. The net income was achieved through the high quality of the Haynes property acquired in February, 2002 and through economies of scale as the Corporation increases its production base.

Earnings *($ millions)*



Earnings per Share *($)*



Cash flow for the year ended December 31, 2003 was $11,761,467, an increase of 153% over the cash flow of $4,649,299 in 2002. This increase was due primarily to increased production realized in 2003 as a result of the development at the Haynes property in late 2002 and during 2003. This increased cash flow also resulted from commodity prices realized by the Corporation which increased by 22% from an average of $31.14 per boe in 2002 to $38.04 per boe in 2003.

The increase in cash flow per share from $0.09 in 2002 to $0.20 in 2003, while significant (122%), was less than on an absolute basis as a result of the increase in the basic weighted average number of shares outstanding from approximately 54.8 million to approximately 60.3 million, which is a 10% increase.

CAPITAL EXPENDITURES AND CAPITAL RESOURCES

The Corporation's capital expenditures amounted to $14,701,868 in the year ended December 31, 2003 as compared to $22,999,558 in 2002. The decrease in capital expenditures in 2003 over 2002 capital expenditures reflects the inclusion in the prior year's capital expenditures of the purchase price of the central Alberta properties, which was $10,961,972 for 2002.

The following table sets forth a summary of the Corporation's capital expenditures incurred for the years ended December 31, 2003 and 2002.

Capital Expenditures

Years Ended December 31 ($)	2003	2002
Property acquisitions	328,079	11,715,567
Land	888,910	1,221,998
Exploration		
– drilling and completions	4,019,898	1,142,158
Exploration – seismic	281,352	574,490
Exploration – other	418,893	234,445
Development		
– drilling and completions	3,791,907	4,960,273
Development – other	746,085	206,742
Well equipment and facilities	3,592,073	2,511,101
Capitalized general		
and administrative expenses	606,592	344,989
Corporate acquisitions	–	–
Total finding and on-stream costs	14,673,789	22,911,763
Administrative assets	28,079	87,795
Total capital expenditures	14,701,868	22,999,558

The following table sets forth a summary of the Corporation's capital resources for the years ended December 31, 2003 and 2002:

Capital Resources

Years Ended December 31 ($)	2003	2002
Cash flow from operations	11,761,467	4,649,299
Changes in working capital	537,800	276,811
Site restoration costs paid	(434,543)	(260,193)
Production loan and		
other long-term liabilities	(2,725,821)	7,458,345
Equity Issues	–	9,319,153
Disposition of assets	6,134,846	1,645,527
Repurchase of common shares	(615,466)	–
Total capital resources	14,658,283	23,088,942

CHANGES IN ACCOUNTING STANDARDS

Accounting Standards Adopted in 2003

The Canadian Institute of Chartered Accountants ("CICA") amended the stock option compensation and other stock based payments accounting standard during 2003. The Corporation has chosen to early adopt the standard and accordingly, the consolidated financial statements for the 2003 calendar year reflect this. Please see notes 2, 3 and 8 to the consolidated financial statements of the Corporation for further details. The effect on the Corporation in 2003 is not material.

Accounting Standards to be Adopted in 2004

Oil and Gas Full Cost Accounting Guideline

During 2003 the CICA updated the oil and gas full cost accounting guideline. The new standard takes effect for fiscal years beginning on or after January 1, 2004 or earlier on a voluntary basis. The Corporation has chosen not to early adopt this standard. The main change to this standard that affects Case is how the impairment of petroleum and natural gas properties and equipment is determined, ie, the ceiling test calculation.

The ceiling test calculation is now a two-step process, the first being to identify whether potential impairment exists and the second step being to measure and record any impairment. The first step must be performed annually utilizing the external independent engineering report. In respect of each quarter, a review must be undertaken to determine if there have been any occurrences which would give rise to impairment. The second step must be performed whenever potential impairment is identified by the first step.

The first step identifies potential impairment when the carrying value of petroleum and natural gas properties exceeds the estimated undiscounted future net cash flows from the proved reserves attributable to such properties. For this purpose Case uses the future net revenue (undiscounted) from its proved reserves as estimated by its independent reserve evaluator using forecast prices and costs.

The second step measures the impairment as the amount by which the carrying value of petroleum and natural gas properties exceeds the fair value of proved and probable reserves attributed to such properties plus the costs of properties to which no probable reserves have been attributed. The determination of fair value will be based to a large extent on the market conditions at such time.

Case has applied the first step of this process as at January 1, 2004 and no potential impairment has been identified by that comparison.

Asset Retirement Obligation

The CICA issued a new standard relating to asset retirement obligations which is applicable for fiscal years beginning on or after January 1, 2004 or earlier on a voluntary basis. The Corporation has chosen not to early adopt this standard. This standard requires the recognition in the financial statements of the liability associated with the net present value of future site reclamation costs when the liability is incurred. These obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes to the underlying costs. The asset retirement cost is to be capitalized and amortized into income over time. The impact on the Corporation is currently being evaluated. At December 31, 2003 the undiscounted estimated future well abandonment and site reclamation costs were $1,963,000.

Hedging Relationships

During 2003 the CICA updated its guideline relating to hedging transactions in order to address the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. This new standard is effective for fiscal years beginning on or after July 1, 2003. The guideline requires the formal documentation by the Corporation of the designation of a hedging relationship when the designation occurs. Formal documentation of the effectiveness of a hedging relationship is also required in order to be able to use hedge accounting. The purpose of this standard is to ensure that counterbalancing gains, losses, revenue and expenses are recognized in income in the same period or periods. The application of this standard by the Corporation, at this time, in its 2004 fiscal year will have no material impact as there are no hedges outstanding as at January 1, 2004 and Case has not entered into any subsequent to year end.

SELECTED QUARTERLY INFORMATION

	Year Ended December 31, 2003				Year Ended December 31, 2002			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Total petroleum and natural gas revenue	7,094,210	5,854,678	5,050,495	5,352,672	1,299,093	2,590,623	2,966,785	5,415,708
Total revenue, net of royalties	5,370,421	4,417,899	3,999,260	4,161,141	1,093,838	2,060,178	2,285,222	4,192,976
Net earnings (loss)	2,819,445	1,893,660	1,409,450	617,744	(10,952)	224,788	515,753	1,868,098
Net earnings (loss) per share								
basic	0.05	0.03	0.02	0.01	–	–	0.01	0.03
diluted	0.05	0.03	0.02	0.01	–	–	0.01	0.03
Cash flow from operations	3,812,139	2,959,619	2,549,377	2,440,332	222,486	707,655	1,173,554	2,545,604
Cash flow from operations per share								
basic	0.06	0.05	0.04	0.04	–	0.01	0.02	0.04
diluted	0.06	0.05	0.04	0.04	–	0.01	0.02	0.04
Book value of total assets	23,686,952	21,828,137	23,673,386	28,019,778	13,993,331	14,311,674	18,349,879	24,080,759
Production loan	4,042,305	1,452,067	945,317	4,732,524	4,123,443	4,311,725	6,618,601	7,458,345
Total debt	4,580,997	1,751,659	3,238,741	6,125,264	4,177,982	4,369,099	7,406,948	8,269,700
Shareholders' equity	15,586,504	16,864,698	18,274,147	18,901,131	8,297,101	8,463,702	8,941,626	12,767,059
Common shares outstanding end of period	60,792,679	60,000,179	60,000,179	60,000,179	57,198,217	57,198,217	57,198,217	60,792,679
Weighted average common shares outstanding								
basic	60,792,679	60,401,657	60,000,179	60,000,179	44,975,995	57,198,217	57,198,217	59,514,050
diluted	61,189,393	61,164,640	61,909,131	62,074,464	44,975,995	57,198,217	57,198,217	59,514,050

Discussion of 2003 Fourth Quarter Results

The most notable change in the fourth quarter was that net earnings were reduced due to increased depletion and depreciation expense resulting from higher finding and development costs during the quarter, increased future income taxes and increased general and administrative expense resulting from employee bonuses. The demand revolving loan increased during the fourth quarter because capital expenditures of approximately $5 million were incurred during that quarter.

CONTRACTUAL COMMITMENTS

The Corporation is committed under an operating lease for its office premises with the following aggregate minimum lease payments to the expiration of the lease on December 31, 2004.

2004	215,000

The Corporation is committed under an operating lease for one of its compressors at its Haynes field with the following aggregate minimum lease payments to the expiration of the lease on December 23, 2004.

2004	174,000

CRITICAL ACCOUNTING ESTIMATES

Estimates of Petroleum and Natural Gas Reserves and Depletion and Depreciation

The Corporation, at least annually, engages a qualified independent reserves evaluator to provide an estimate of the Corporation's year-end reserve volumes and associated future net revenues. The Corporation provides relevant production, financial and technical data to the reserves evaluator. The Corporation considers these estimates to be critical estimates for the reasons discussed below. These estimates are herein referred to as the "Reserve Estimates". For further details on the methodology and assumptions relating to the Reserve Estimates and the changes to the Reserve Estimates during the past two financial years see the Corporation's Annual Report and the reserves data that will be filed by the Corporation on SEDAR at www.sedar.com in accordance with National Instrument 51-101.

The Reserve Estimate relating to the volume of reserves is utilized in the calculation of depletion and depreciation expense in the financial statements. The reserves volume together with the production volume for a relevant period is utilized in calculating a depletion rate for the Corporation. This depletion rate is used together with other accounting information to determine the depletion and depreciation for that period.

Should the Reserve Estimate relating to the volume of reserves be materially incorrect it would have a material impact on the Corporation's recorded amount of depletion and depreciation expense. The Reserve Estimates will from time to time change based on changes to the many factors underlying the Reserve Estimates, which include but are not limited to, production performance, commodity prices, capital expenditures, technical interpretations based on activity and new information and additional activities not contemplated in the preparation of the Reserve Estimate. Management believes that only a significant change to the Reserve Estimates would have sufficient impact on the Corporation's depletion and depreciation expense to cause a material change to the financial condition of the Corporation.

The Reserve Estimates are also relied upon by the Corporation's major lending institution in determining the production loan amount available to the Corporation under its credit facility. The lending institution relies on all components of the Reserve Estimates and the underlying assumptions, except for the price forecast. The lending institution in most instances will utilize its own price forecast. The availability of this credit facility is important to the Corporation because it relies on this source of capital to fund its capital budget in excess of its internally generated funds. Should the Reserve Estimates change materially and negatively, it may have a material affect on the amount of capital available to the Corporation under this credit facility, which would impair the Corporation's ability to pursue its business plans.

Estimates of Petroleum and Natural Gas Production and Revenue

The Corporation receives its revenue for a particular month on the 25th day of the following month. For the 2003 consolidated financial statements the Corporation recorded actual production and revenue amounts for each of the accounting months, as the regulatory reporting requirements allowed sufficient time to obtain and process the necessary data to do so.

For the 2004 calendar year, the regulatory reporting requirements have been reduced from 60 days to 45 days for the quarterly reporting period and from 140 days to 90 days for the annual reporting period. This may not allow enough time to record actual amounts into each of the accounting months. The Corporation will therefore be required to estimate both production and prices in order to generate an estimate of petroleum and natural gas revenue for the last month in each reporting period.

In order to estimate production the Corporation will rely on estimates of production generated by its operations staff. Case's field operators regularly review the charts and meters associated with all of our operated properties and from these readings, they calculate the amount of raw production expected to be delivered directly to sales or to a or processing facility for processing and ultimate sale. The Corporation's operations staff then applies shrinkage factors to these estimates of raw production to estimate sales volumes. These shrinkage factors which are based on operating experience and take into account fuel loss, temperature differences, processing losses, flaring or other product loss events. The relevant shrinkage factors can vary from month to month due to many factors that affect the commodities as they travel to their final sales destination.

These production estimates are compared to actual sales data generated by the production accounting department as soon as actual data becomes available, which is usually within 20 days after the end of the particular month. This control should reduce the possibility of materially misstating the production for the last month in each reporting period. For non-operated properties we rely on information provided to us by the operator of such property together with our knowledge of the property. This information may not be available in a timely fashion and as such estimates are based on the best information available at that time.

The production estimates described above are used by the Corporation to estimate revenues, royalties, operating costs and depletion and depreciation for the relevant period. To the extent that production volume estimates vary materially from the actual production volumes, the amount the Corporation records in respect of revenues, royalties, operating costs and depletion and depreciation may also be materially overstated or understated.

Management does not believe that if its production estimates vary from the actual amounts it will have a material impact on the financial condition of the Corporation because the Corporation is able to assess the general reasonableness of the estimate in an overall sense by comparison against the production data and gross revenue actually received on the 25th day following the particular month so as to assess the validity of the estimate.

Current income taxes

The Corporation is required to file a corporate income tax return annually and is required to pay any income tax liability in a timely manner. As a result of this requirement the Corporation must estimate at the end of each reporting period its potential current income tax liability for the particular fiscal year in question. In order to determine the Corporation's income tax liability for the fiscal year the Corporation must estimate revenue, royalties (net of ARTC), other income, operating expenses, general and administrative expenses, interest expense, capital expenditures and other relevant items. The Corporation makes these estimates using its budget approved by the Board of Directors and adjusts it for any actual history up to the time the estimate is made. The critical estimates in this process are production rates, commodity prices, capital expenditures and the tax category of these capital expenditures for the entire fiscal period. The risk of materially misstating the amount of current taxes payable is highest in respect of the first quarter and reduces for each quarter as more actual data can be used and the estimated amounts apply for a shorter period.

To the extent that the estimate of current taxes payable varies materially from the actual amount of taxes payable, the Corporation may be required to pay an unexpected material amount of taxes which may adversely affect the Corporation's financial condition.

The most critical part of this estimate is the estimate of the amount and tax category of capital expenditures that will be incurred during the relevant year as those expenditures form the basis of any new tax pools that the Corporation can use as deductions in respect of that year. To the extent that a material amount of capital allocated to exploration drilling which is 100% deductible in the fiscal year, is ultimately allocated to development drilling which is only 30% deductible in the fiscal year, the Corporation's current taxes payable can change materially. There is a risk that wells that are drilled in an effort to encounter a new oil or natural gas accumulation can encounter an already discovered accumulation thus changing the tax category from exploration expenditure to development expenditure. This risk is significant because many wells drilled by Case are drilled in proximity to other wells and the tax category of the expenditures is not finally determined until drilling is completed.

To mitigate this risk the Corporation allocates its entire budget to tax categories based on discussions with its operations group and reviews the continuing validity of these categorizations at each reporting period.

OUTLOOK

Case has a strong balance sheet that will enable it to capture future opportunities while reducing the amount of equity financing that may be required. Case is presently experiencing higher than expected cash flows as a result of very high commodity prices for both oil and natural gas. We are well positioned with low a operating cost property at Haynes to profitably operate in a lower commodity price environment.

Case's priority is to diversify its asset base by establishing another core area. The Haynes property will provide the cash flow base from which case can grow into other areas.

We have a team of highly skilled technical experts who are engaged in continuously evaluating opportunities and we firmly believe that the rigorous application of our team's skills will ultimately uncover an appropriate opportunity to enhance the value of Case for its shareholders.

CASE RESOURCES INC. – 2002 and 2003

Consolidated Financial Statements

MANAGEMENT'S REPORT

To the shareholders of Case Resources Inc:

The consolidated financial statements of Case Resources Inc. were prepared by management within the acceptable limits of materiality and are in accordance with accounting principles generally accepted in Canada. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the consolidated financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgements made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records properly maintained to facilitate the preparation of financial statements for reporting purposes.

Deloitte & Touche LLP, an independent firm of Chartered Accountants appointed by shareholders, have conducted an examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee, consisting of a majority of non-management directors, has met with representatives of Deloitte & Touche LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

A. Jeffery Tonken
President
and Chief Executive Officer

Bruno P. Geremia
Vice President
and Chief Financial Officer

AUDITORS' REPORT

To the shareholders of Case Resources Inc:

We have audited the consolidated balance sheets of Case Resources Inc. as at December 31, 2003 and 2002 and the consolidated statements of earnings and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Calgary, Alberta

February 27, 2004

CONSOLIDATED STATEMENTS OF EARNINGS AND DEFICIT

For the years ended December 31 *($)*	2003	2002
REVENUE		
Petroleum and natural gas	**23,352,055**	12,272,209
Royalties, net of ARTC	**(5,407,216)**	(2,647,660)
Other	**3,882**	7,665
	17,948,721	9,632,214
EXPENSES		
Operating	**3,394,798**	2,823,502
General and administrative	**2,628,722**	1,892,176
Interest	**142,551**	212,461
Depletion and depreciation	**4,564,929**	2,587,242
	10,731,000	7,515,381
EARNINGS BEFORE TAXES	**7,217,721**	2,116,833
TAXES *(Note 9)*		
Current	**30,422**	54,776
Future income tax expense (recovery)	**447,000**	(535,630)
	477,422	(480,854)
NET EARNINGS	**6,740,299**	2,597,687
DEFICIT, BEGINNING OF YEAR	**(7,417,495)**	(10,015,182)
Common shares repurchased *(Note 6(f))*	**(353,941)**	–
DEFICIT, END OF YEAR	**(1,031,137)**	(7,417,495)
Net earnings per common share		
– basic and diluted *(Note 7)*	**0.11**	0.05
Weighted average number of shares		
– basic	**60,295,684**	54,768,235
– diluted	**61,673,113**	54,785,696

CONSOLIDATED BALANCE SHEETS

As at December 31 *($)*	2003	2002
ASSETS		
CURRENT		
Cash	**69,213**	112,798
Accounts receivable	**2,323,642**	2,718,552
Deposits and prepaid expenses	**41,917**	48,417
	2,434,772	2,879,767
Petroleum and natural gas properties *(Note 4)*	**25,585,006**	21,200,992
	28,019,778	24,080,759
LIABILITIES		
CURRENT		
Accounts payable and accrued liabilities	**3,827,512**	3,691,122
Revolving production loan *(Note 5)*	**4,732,524**	7,458,345
	8,560,036	11,149,467
Future income taxes	**447,000**	–
Site restoration provision	**111,611**	164,233
	9,118,647	11,313,700
SHAREHOLDERS' EQUITY		
Share capital *(Note 6)*	**19,923,029**	20,184,554
Contributed surplus *(Note 8)*	**9,239**	–
Deficit	**(1,031,137)**	(7,417,495)
	18,901,131	12,767,059
	28,019,778	24,080,759

APPROVED BY THE BOARD

Larry A. Shaw

Larry A. Shaw
Director

Jeff Tonken

A. Jeffery Tonken
Director

CONSOLIDATED STATEMENTS OF CASH FLOWS

[illegible] years ended December 31 [illegible]	2003	2002
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net earnings	6,740,299	2,597,687
Adjustments for:		
General and administrative *(Note 8)*	9,239	–
Depletion and depreciation	4,564,929	2,587,242
Future income tax expense (recovery)	447,000	(535,630)
Cash flow from operations	11,761,467	4,649,299
Site restoration expenditures	(434,543)	(260,193)
Changes in non-cash working capital *(Note 12)*	1,572,659	(1,229,032)
	12,899,583	3,160,074
FINANCING		
Increase (decrease) to revolving production loan	(2,725,821)	7,458,345
Issuance of share capital, net of related expenses *(Note 6)*	–	9,319,153
Repurchase of common shares *(Note 6(f))*	(615,466)	–
	(3,341,287)	16,777,498
INVESTING		
Petroleum and natural gas properties and equipment	(14,373,789)	(11,283,991)
Purchase of petroleum and natural gas properties and equipment	(328,079)	(11,715,567)
Sale of petroleum and natural gas properties and equipment *(Note 4)*	6,134,846	1,645,527
Changes in non-cash working capital *(Note 12)*	(1,034,859)	1,505,843
	(9,601,881)	(19,848,188)
NET INCREASE (DECREASE) IN CASH	(43,585)	89,384
CASH, BEGINNING OF YEAR	112,798	23,414
CASH, END OF YEAR	69,213	112,798

1. INCORPORATION AND NATURE OF OPERATIONS

Case Resources Inc. ("Case") was incorporated under the Business Corporations Act (Alberta) on March 12, 1993 as 558818 Alberta Inc. It changed its name from Touchstone Petroleum Inc. to Case Resources Inc. on May 17, 2001. On January 1, 2002, Case incorporated a wholly-owned subsidiary for the purpose of managing its heavy oil business. Case (the "Corporation") and its wholly-owned subsidiary, Case Sub Ltd. ("Sub"), are currently engaged in the exploration for and the development and acquisition of, petroleum and natural gas reserves in Western Canada.

2. SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), within an acceptable level of materiality, utilizing the framework of the accounting policies below.

Basis of accounting

The Corporation's consolidated financial statements include the accounts of Case and its wholly owned subsidiary, Sub. All inter-company transactions and balances have been eliminated upon consolidation.

Measurement uncertainty

The preparation of timely financial statements necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. These estimates will affect assets, liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, as well as revenues and expenses during the reporting periods. Such estimates are based on informed judgements made by management. Actual results could differ materially from those estimated.

Amounts recorded for depletion, depreciation, site restoration and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves which include estimates of future commodity prices, future costs and other relevant assumptions. The Corporation's reserves are estimated and evaluated, at a minimum, annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty and the impact of changes in such estimates on the consolidated financial statements of future periods could be material.

Cash and cash equivalents

Cash includes cash and cash-like short-term investments which can be liquidated into cash on short notice. Short-term investments are comprised of risk-free, interest bearing securities.

Petroleum and natural gas properties

The Corporation follows the full-cost method of accounting for petroleum and natural gas properties whereby all costs relating to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs may include lease and land acquisition costs, geological and geophysical expenses, lease rentals and other costs on non-producing properties, costs of drilling and completing both productive and non-productive wells, production equipment and corporate expenses directly related to acquisition, exploration and development activities. These costs along with estimated future capital costs in the current reserve report related to the development of proved reserves, net of salvage values are included in the depletion calculation. Costs of acquiring and evaluating unproved properties may be excluded from the depletion base until it is determined whether proved reserves are attributable to the properties or impairment has occurred.

Depletion of petroleum and natural gas properties and depreciation of production equipment is provided on the unit-of-production basis using estimated gross (before royalties) proved oil and natural gas reserves as determined by independent reservoir engineers. Natural gas reserves and production are converted, at a ratio of six thousand cubic feet of natural gas to one barrel of oil, for depletion and depreciation purposes.

Proceeds from the sale of properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion and depreciation by 20% or more.

The Corporation performs a ceiling test calculation quarterly to net capitalized costs to ensure that such costs do not exceed the estimated undiscounted value of future net revenues from the production of its total proved reserves, plus the cost of its undeveloped lands, net of impairments. Future net revenues are calculated using either period end or the last month average sales prices and include an allowance for estimated future general and administrative expenses, financing costs, site restoration costs, income taxes and future development expenditures.

Estimated future site restoration and abandonment costs are provided for over the life of the total proved reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Corporation's engineers based on current costs and technology in accordance with the current legislation and industry practices. The annual charge is included in the depletion expense and actual site restoration and abandonment expenditures are applied against the accumulated provision account.

Joint venture activities

A portion of the Corporation's exploration and production activities are conducted jointly with others and, accordingly, the accounts reflect only the Corporation's proportionate interest in such activities.

Revenue recognition

The Corporation records its petroleum and natural gas revenue at the time of physical transfer to a purchaser.

Per share amounts

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the period. The Corporation utilizes the treasury stock method of calculating diluted earnings per share. Under this method, the diluted weighted average number of common shares is calculated assuming the proceeds from the exercise of stock options are to be used to re-purchase common shares of the Corporation at the average market price during the period.

Future income taxes

The Corporation accounts for its income taxes using the liability method. Under this method, future income tax assets and liabilities are determined based on the differences between the financial reporting and tax bases of assets and liabilities using the tax rates anticipated to apply in relevant future periods.

Flow-through shares

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with tax legislation. The Corporation records the carrying value of the expenditures in petroleum and natural gas properties as incurred and concurrently, records a future income tax liability in relation to the benefits renounced with a corresponding reduction to share capital.

Stock options

The Corporation has established a stock option plan whereby officers, employees, directors and service providers may be granted options to purchase common shares at a fixed price not less than the fair market value of the stock at the time of grant. In order to calculate the compensation expense, the fair value of the stock options is estimated using the Black-Scholes option-pricing model that takes into account, as of the grant date: exercise price, expected life, current price, expected volatility, expected dividends, and risk-free interest rates. The compensation expense recorded in the consolidated financial statements is based upon only the fair value of the stock options granted on or after January 1, 2003. The compensation expense related to the fair value of the stock options granted on or after January 1, 2002 and prior to January 1, 2003 is disclosed only as pro-forma information in the notes to the consolidated financial statements (see Note 8). Stock options granted prior to January 1, 2002 are not accounted for in the compensation expense nor are they required to be disclosed in the pro-forma disclosure.

The fair value calculated related to stock options granted on or after January 1, 2003 is deferred and charged against earnings, as compensation expense, over the vesting period of the stock options with a corresponding increase in contributed surplus. The related compensation expense is included in general and administrative expense.

Consideration paid to the Corporation upon the exercise of the stock options is recorded as an increase to share capital, and an adjustment is made to transfer to share capital the compensation expense previously recognized in contributed surplus for the specific stock options exercised.

The Corporation has not incorporated an estimated forfeiture rate for stock options in determining the stock option fair value in order to calculate its compensation expense, as the Corporation has assumed that all stock options granted will vest. Accordingly, forfeitures are accounted for as they occur and are treated as a change in estimate. The cumulative effect of the change on current and prior periods is recognized in the period of the change in estimate. In the event that vested options expire without being exercised, previously recognized compensation costs associated with such stock options are not reversed.

The pro-forma effect on net earnings and net earnings per share had compensation expense been recognized in the consolidated financial statements using the fair value method of accounting for stock options granted on or after January 1, 2002, and before January 1, 2003 is described in Note 8.

Financial instruments

The Corporation has determined that the fair value of the financial instruments consisting of cash, accounts receivable, accounts payable and accrued liabilities are not materially different from the carrying value of such instruments reported on the balance sheet due to their short-term nature. In respect of the revolving production loan, its carrying value is not materially different than its fair value as the facility bears interest based on the prevailing prime interest rate. A substantial portion of the Corporation's accounts receivable are with commodity marketers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risk.

The nature of the Corporation's operations result in exposure to fluctuations in commodity prices, currency exchange rates and interest rates. The Corporation may from time to time manage its exposure to these risks through the use of physical contracts or financial instruments. The Corporation is exposed to potential credit losses in the event of non-performance by counterparties to these arrangements. The Corporation tries to mitigate this risk by only dealing with credit worthy counterparties. Gains and losses on derivative contracts are recognized in income in the same period that the transactions are settled. The fair values of derivative contracts are not recorded in the consolidated balance sheets.

3. CHANGE IN ACCOUNTING POLICIES

New Accounting Policy Adopted in 2003

Stock options

Effective January 1, 2003, the Corporation elected to prospectively adopt the fair value method of accounting for stock options granted on or after January 1, 2003 under its stock-based compensation plan as recommended by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, compensation expense has been recognized in general and administrative expense in the consolidated statement of earnings with a corresponding increase recorded to contributed surplus in the consolidated balance sheet using the fair value method as described in Note 2 and Note 8.

In prior periods, the Corporation accounted for stock option compensation using intrinsic values as defined by the CICA. The Corporation granted all of its stock options at or above market value, thereby having no intrinsic value at the time of grant. Accordingly, the Corporation was not required to recognize any compensation expense in the prior period consolidated financial statements.

4. PETROLEUM AND NATURAL GAS PROPERTIES

2003

$	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	43,315,716	17,842,131	25,473,585
Furniture and office equipment	183,971	72,550	111,421
	43,499,687	17,914,681	25,585,006

2002

$	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	34,776,773	13,691,131	21,085,642
Furniture and office equipment	155,892	40,542	115,350
	34,932,665	13,731,673	21,200,992

The Company has capitalized general and administrative expenses related to exploration and development activities of $891,586 (2002 - $344,989).

On February 28, 2002, the Corporation completed an acquisition of light oil and natural gas producing properties in central Alberta. The acquisition had an effective date of November 1, 2001 only for the purpose of determining the final purchase price. After taking into account the four month adjustment period from November 1, 2001 to February 28, 2002, the acquisition price recorded in 2002 is $10,961,972. The Corporation has recorded production volumes, revenue and expenses only from March 1, 2002 forward.

During 2003, the total expenditures incurred, under the terms of a flow-through share agreement, without tax base is $Nil (2002 - $1,862,558). These expenditures have no cost basis for income tax purposes and they are reflected as such in the computation of future income taxes. With respect to share capital, see Note 6. The Corporation has satisfied all of its obligations with respect to all of its flow-through share subscription agreements relating to 2002. The Corporation did not have any flow-through share obligations in 2003.

On February 28, 2003, in two separate transactions, the Corporation disposed of a portion of its petroleum and natural gas properties located mainly in the West Hazel area of Saskatchewan for net proceeds of $2,340,697. Both transactions were effective January 1, 2003 for purposes of determining the purchase price. These consolidated financial statements include the revenue and expenses from the properties up to and including the close of the transactions on February 28, 2003.

On April 16, 2003, the Corporation disposed of most of its non-core petroleum and natural gas properties located mainly in southern Alberta for net proceeds of $3,745,649. The transaction was effective April 16, 2003 for purposes of determining the purchase price. These consolidated financial statements include the revenue and expenses from the properties up to and including the close of the transaction on April 16, 2003.

As at December 31, 2003, the estimated future site restoration costs to be amortized over the remaining proved reserves are $1,963,000 (2002 - $1,426,000). Site restoration costs of $381,921 (2002 - $171,000) have been amortized and included in depletion and depreciation expense in the current year.

In calculating the depletion provision for the year ending December 31, 2003, the carrying value of undeveloped properties that were excluded from the costs subject to depletion were $Nil (2002 - $Nil).

The Corporation performed a ceiling test calculation at December 31, 2003. The sales prices, in Canadian dollars, at the wellhead used for the ceiling test were $38.31 per barrel for light oil, $21.56 per barrel for heavy oil and $6.40 per thousand cubic feet for natural gas. As a result of the ceiling test computation, the Corporation is not required to write down its petroleum and natural gas properties at December 31, 2003.

Effective January 1, 2004, the Corporation is required to perform a ceiling test using the new accounting guideline (AcG-16 oil and gas accounting - full cost) calculation as at January 1, 2004. The Company has performed the required ceiling test calculation and no write-down is required.

5. REVOLVING PRODUCTION LOAN FACILITY

At December 31, 2003, the Corporation had a revolving production loan facility (the "facility") with a major lender. Direct borrowings under this facility bear interest at prime plus 0.25%. If the debt to equity ratio is greater than 1:1, determined at the beginning of each quarter, the rate can be increased to prime plus 0.50%, until such time as the debt to equity ratio is less than or equal to 1:1. The security pledged for the loan facility consists of a security interest in all of the Corporation's property and assets.

The maximum amount that can be drawn upon this facility is determined by the lender from time to time after assessing the Corporation's total proved reserves. The Corporation is subject to an annual review in May of each year. At December 31, 2003, the maximum amount available under this facility was $13,000,000 based on the Corporation's then current engineering report, current production reports and the lender's evaluation guidelines and oil and natural gas price forecasts.

The lender classifies the Corporation's revolving production loan facility as a demand loan, however, the lender is not aware at this time of any facts, events, or occurrences, which would cause the lender to demand the loan prior to May 31, 2004 (the next annual review date), provided there is no adverse change in the financial position of the Corporation. This facility is demand in nature and, pursuant to the CICA pronouncement, is presented as a current liability.

6. SHARE CAPITAL

(a) Authorized:

Unlimited number of Common Voting Shares without nominal or par value

Unlimited number of First Preference Shares

Unlimited number of Second Preference Shares

The First and Second Preferred Shares may be issued in one or more series and the directors are authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series.

(b) Issued:

	Number of Common Shares	Amount $
Balance, December 31, 2001	32,198,218	11,401,031
Shares issued on private placement, net *(Note 6(c))*	24,999,999	7,004,632
Shares issued on private placement, net (Note 6(d))	3,394,462	2,115,471
Shares issued on private placement, net *(Note 6(e))*	200,000	199,050
Future income tax liability on flow-through share expenditures incurred	–	(782,274)
Future income tax benefit on share issue costs	–	246,644
Balance, December 31, 2002	60,792,679	20,184,554
Shares repurchased *(Note 6(f))*	(792,500)	(261,525)
Balance, December 31, 2003	**60,000,179**	**19,923,029**

(c) On February 14, 2002, the Corporation issued 24,999,999 common shares through a private placement at a price of $0.30 per share for gross proceeds of approximately $7,500,000. Net proceeds were $7,004,632.

(d) On October 31, 2002, the Corporation issued 3,394,462 common shares through a private placement at a price of $0.65 per share for gross proceeds of approximately $2,206,400. Net proceeds were $2,115,471.

(e) On December 19, 2002, the Corporation issued 200,000 flow-through common shares through a private placement at a price of $1.00 per share for net proceeds of $199,050. Pursuant to a flow-through share agreement, the Corporation renounced $200,000 of income tax deductions in 2002 to the subscribers of these shares. At December 31, 2002, $200,000 has been spent on qualifying expenditures.

(f) During the second quarter of 2003, the Corporation purchased 792,500 of its own common shares through its previously announced Normal Course Issuer Bid. The total cash consideration paid for the common shares including commissions was $615,466 for an average price of $0.78 per common share. The common shares have been cancelled. The Corporation recorded as a reduction of share capital $261,525 for an average price of $0.33 per common share which equates to the Corporation's recorded book value per common share. The remaining $353,941 or $0.45 per common share was recorded as a reduction to retained earnings.

7. STOCK OPTIONS AND NET EARNINGS PER SHARE

Stock options

The Corporation has established a stock option plan whereby officers, directors, employees and service providers may be granted stock options to purchase common shares at a fixed price not less than the fair market value of the common shares at the time of grant. Options issued under the plan vest at the rate of one-third on each anniversary date of the stock option grant. All stock options granted are for a five year term. At December 31, 2003, the Company had approved for issuance 5,719,821 options (2002 - 5,719,821) of which 5,379,750 were issued (2002 - 5,341,250).

A summary of the changes during the year ended December 31, 2003 and the Corporation's outstanding options as at December 31, 2003 is presented below:

	Number	Weighted Average Exercise Price $
Outstanding, December 31, 2001	1,286,250	$0.82
Granted	4,123,750	$0.68
Exercised	–	
Repurchased and/or cancelled	(68,750)	$0.63
Outstanding, December 31, 2002	5,341,250	$0.71
Granted	77,500	$1.01
Exercised	–	
Cancelled	(39,000)	$0.69
Outstanding, December 31, 2003	**5,379,750**	**$0.72**

Date of Grant	Number Outstanding at December 31, 2003	Date of Expiry	Exercise Price $	Number Exercisable at December 31, 2003
June 13, 2000	37,500	August 1, 2005	0.40	37,500
September 20, 2000	905,000	September 20, 2005	0.85	905,000
October 30, 2000	125,000	October 30, 2005	1.04	125,000
May 4, 2001	200,000	May 4, 2006	0.62	133,334
March 7, 2002 to August 21, 2002	2,590,000	March 7,2007 to August 21, 2007	0.64 to 0.66	863,333
September 30, 2002 to December 18, 2002	1,444,750	September 30, 2007 to December 18, 2007	0.70 to 0.76	481,583
May 8, 2003 to December 1, 2003	77,500	May 8, 2008 to December 1, 2008	0.84 to 1.17	–
	5,379,750			2,545,750

Net earnings per share

Diluted net earnings per share includes additional common shares for the dilutive impact of stock options outstanding at December 31, 2003. In determining the diluted earnings per share, the Corporation determined that 5,214,750 (2002 - 237,500) stock options had a dilutive impact of increasing the weighted average number of common shares by 1,377,429 (2002 - 17,461). This amount has no material impact on the net earnings per share calculation.

8. STOCK OPTION COMPENSATION

The Corporation has used the fair value method to determine a fair value for stock options granted on or after January 1, 2003, in order to determine stock option compensation expense. The Corporation recorded $9,239 of compensation expense in the consolidated statement of earnings. This amount was included in the general and administrative expense, with a corresponding increase to contributed surplus in the consolidated balance sheet. Using the fair value method the weighted average fair value of stock options granted during the year ended December 31, 2003 was $0.72 per share.

In 2002 and prior years, the Corporation accounted for its stock-based compensation plans using intrinsic values rather than the fair value method. The exercise price, of all stock options granted by the Corporation, were at or above the current market price of the common shares at the time of grant and therefore, no compensation expense was recognized in the prior consolidated financial statements.

The following table details the impact of using the fair value method to calculate compensation expense for stock options granted on or after January 1, 2002 and prior to January 1, 2003. The Corporation's net earnings and net earnings per share on a pro forma basis would be as follows:

$ 000's except per share	2003	2002
Pro forma compensation expense (fair value method)	**554**	287
Net earnings		
As reported	**6,839**	2,597
Pro forma	**6,285**	2,310
Net earnings per common share		
Basic and diluted		
As reported	**0.11**	0.047
Pro forma	**0.10**	0.042

The fair value of each option granted after January 1, 2002 was determined on the date of the grant using the Black-Scholes option-pricing model. The weighted average assumptions used in calculating the fair values are set forth below:

	2003	2002
Risk-free interest rate	**5.05%**	5.05%
Expected maturity (years)	**5.0**	5.0
Expected volatility	**64.49%**	63.43%
Dividend per share	**$0.00**	$0.00

9. INCOME AND OTHER TAXES

As at December 31, 2003, the Corporation has exploration, development, acquisition and facility costs available for deduction against future taxable income of approximately $23,414,000 (2002 - $23,308,000). In addition, at December 31, 2003, the Corporation has non-capital losses carried forward for income tax purposes of approximately $Nil (2002 - $2,821,000).

The provision for income taxes differs from the result that would be obtained by applying the combined current year Canadian federal and provincial income tax rates of approximately 41% (2002 - 42%) to the earnings before taxes. The difference results from the following items:

	2003	2002
Computed expected income tax provision	**2,959,266**	889,070
Increase (decrease) in taxes resulting from:		
Non-deductible crown charges	**1,339,639**	715,259
Non-deductible expenses	**33,051**	6,300
Resource allowance	**(1,299,408)**	(526,618)
Alberta Royalty Tax Credits	**(184,500)**	(26,380)
Recognized benefit of non-capital losses and other items	**(2,401,048)**	(1,593,261)
Future income tax expense (recovery)	**447,000**	(535,630)

The Corporation's current tax expense for the year ended December 31, 2003 was $30,422 (2002 - $54,776). The Corporation paid $30,422 (2002 - $26,000) relating to the Large Corporations Tax for the current taxation year. The remaining $Nil (2002 - $28,776) in current taxes relates to Part XII.6 tax. This tax is calculated based upon the month in which resource expenditures are incurred that were previously renounced by the Corporation under the terms of a flow-through share agreement.

10. COMMITMENTS AND CONTINGENCIES

The Corporation is committed under an operating lease for its office premises with the following aggregate minimum lease payments to the expiration of the lease on December 31, 2004:

	$
2004	215,000

The Corporation is committed under an operating lease for one of its compressors at its Haynes field with the following aggregate minimum lease payments to the expiration of the lease on December 23, 2004:

	$
2004	174,000

11. GUARANTEES

The Corporation has various guarantees and indemnifications in place in the ordinary course of business, none of which, as assessed by management, are expected to have a significant adverse impact on the Company's financial statements or operations.

12. SUPPLEMENTARY CASH FLOW INFORMATION

Interest paid on a cash basis for the current year was $142,551 (2002 - $212,461). Current taxes paid on a cash basis for the current year were $30,422 (2002 - $54,776) (see Note 9).

The following table details the components of non-cash working capital provided by (used in) operations:

$	2003	2002
Accounts receivable	**394,910**	(1,946,711)
Deposits and prepaid expenses	**6,500**	258,659
Accounts payable and accrued liabilities	**136,390**	1,964,863
	537,800	276,811
Operating	**1,572,659**	(1,229,032)
Investing	**(1,034,859)**	1,505,843

13. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

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Vice President Exploration and Chief Operating Officer

Bruno P. Geremia, C.A.
Vice President and Chief Financial Officer

James W. Surbey
Vice President, Corporate Development
and Corporate Secretary

Geoff A. Williams, P.Eng.
Vice President

AUDITORS

Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta

EVALUATION ENGINEERS

Gilbert Laustsen Jung
Petroleum Consultants
Calgary, Alberta

SOLICITORS

Borden Ladner Gervais
Calgary, Alberta

BANKERS

Alberta Treasury Branches
Calgary, Alberta

TRANSFER AGENTS

Computershare Investor Services Inc.
Calgary, Alberta

STOCK EXCHANGE LISTING

Toronto Stock Exchange (TSX)
Symbol: **CAZ**

ABBREVIATIONS

API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
bbl	barrels
bbls/d	barrels per day
mbbl	thousands of barrels
boe	barrels of oil equivalent (6mcf = 1 boe)
boe/d	barrels of oil equivalent per day
mboe	thousands of boe
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
TSX	Toronto Stock Exchange
NGL's	natural gas liquids
CAZ	Case Resources Inc.
WTI	West Texas Intermediate Crude Oil

CASE

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